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APPENDIX 10 Power

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GREAT LAKES BASIN FRAMEWORK STUDY

Great Lakes Basin Framework Study

APPENDIX 10

POWER

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This appendix to the *Report of the Great Lakes Basin Framework Study* was prepared at field level under the auspices of the Great Lakes Basin Commission to provide data for use in the conduct of the Study and preparation of the *Report*. The conclusions and recommendations herein are those of the group preparing the appendix and not necessarily those of the Basin Commission. The recommendations of the Great Lakes Basin Commission are included in the *Report*.

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OUTLINE

Report

- Appendix 1: Alternative Frameworks
- Appendix 2: Surface Water Hydrology
- Appendix 3: Geology and Ground Water
- Appendix 4: Limnology of Lakes and Embayments
- Appendix 5: Mineral Resources
- Appendix 6: Water Supply—Municipal, Industrial, and Rural
- Appendix 7: Water Quality
- Appendix 8: Fish
- Appendix C9: Commercial Navigation
- Appendix R9: Recreational Boating
- Appendix 10: Power
- Appendix 11: Levels and Flows
- Appendix 12: Shore Use and Erosion
- Appendix 13: Land Use and Management
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- Appendix 19: Economic and Demographic Studies
- Appendix F20: Federal Laws, Policies, and Institutional Arrangements
- Appendix S20: State Laws, Policies, and Institutional Arrangements
- Appendix 21: Outdoor Recreation
- Appendix 22: Aesthetic and Cultural Resources
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- Environmental Impact Statement

SYNOPSIS

The Great Lakes Basin Power Region conforms to the hydrologic boundary of the Basin and encompasses an area, both land and water, within the United States of about 179 thousand square miles. For purposes of analyzing and forecasting future electric power and water requirements, the Basin has been broken down into river basin groups.

The river basin groups that make up the Power Region vary from the sparsely populated regions of northern Minnesota, Michigan, and Wisconsin to the major urban centers of Milwaukee, Chicago, and Detroit. Accordingly, these population distributions and resulting economic patterns interact with the area's available resources to determine future power requirements.

Currently, there are approximately 365 electric utilities operating totally or partially within the Power Region. They represent all segments of the power industry: private, cooperative, Federal, municipal, and other public systems. The utilities have sufficient generating capacity to satisfy their power needs, and this is expected to continue throughout the study period. Their daily and long-term operations are coordinated by planning groups and reliability councils. Utilities are physically interconnected by

extra-high-voltage transmission lines to insure reliability.

The power generated comes predominantly from fossil-fueled electric plants. Hydroelectric energy sources are located primarily in the eastern portion of the Great Lakes Basin. Nuclear generated power will supply a major portion of the power need by the year 2000. Several large pumped-storage hydroelectric plants are also expected to be constructed.

Steam-electric plants require cooling water for condensing. Therefore, flow-through cooling systems which discharge the condensing water directly back into the Lakes have been employed through the years. However, concern over the effects of thermal discharges has prompted the installation of supplemental closed-cycle systems on some power plants, and more are likely to be built in the future. Power plants also pollute the air, emit nuclear radiation, and generally detract from the beauty of our natural environment. The reconciliation of ecological and environmental values with the growing demands for electric power presents a challenge to the power industry which must be met if the Great Lakes Basin is to maintain its national position and retain its quality of life.

FOREWORD

Appendix 10, *Power*, contains information about the present electric power industry within the Great Lakes Basin and the possibilities for future development. The appendix was produced by the Power Work Group, chaired by the Federal Power Commission. Members of the work group were:

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We gratefully acknowledge the suggestions and comments from various interested parties, including electric utilities, which reviewed the second draft.

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INTRODUCTION

The purpose of Appendix 10, *Power*, is to present the existing and projected electric power and corresponding water needs of the Great Lakes Basin. The timely installation of the power facilities necessary to satisfy those needs will be required if the economic development and growth of the Region is to continue, and the well-being of its people is to be enhanced.

The past and estimated future electric power requirements (to the year 2020) in the Great Lakes Basin Power Region are presented in this appendix. The Power Region conforms with the hydrologic boundary. Data are presented by river basin groups corresponding to the Region's fifteen principal drainage areas. We predicted the types of thermal-electric generating stations which will supply the future power requirements. From these we assessed the possible future demands for cooling water.

The technological advance in electric power generation during recent years has been very rapid and the future progress seems limited only by man's imagination and the application of resources in manpower and funds for research. However, this dramatic advance will not take place without accompanying economic, social, and environmental problems which must be overcome, possibly at the ex-

pense of some technical gains. It is not possible, at this time, to foretell what the country will be like fifty years from now. Therefore, estimates of future power requirements and subsequent water use for cooling purposes must be based primarily on historic trends. It will be necessary to review the estimates periodically as new technology and operating criteria evolve.

While we relied chiefly on established historic trends, the possible influence of improved operating efficiencies has been recognized and taken into account in arriving at the projections. The estimated future load and power supply and the material on environmental considerations are primarily predicated on reports of Regional Advisory Committees appointed to assist the Federal Power Commission in updating the National Power Survey. Working drafts for the Survey and reports filed with the Federal Power Commission by utilities list their firm plans through 1980. However, the controversy regarding the method of cooling, flow-through or closed-cycle, has not been resolved. Therefore, we present two cases, one for each method, and the effect that each would have on the water requirements for power generation and associated consumptive use.

Section 1

DESCRIPTION OF THE BASIN AS RELATED TO ELECTRIC POWER PRODUCTION AND REQUIREMENTS

1.1 Great Lakes Basin Power Region

The Great Lakes Basin is defined for this study as the drainage basin of Lakes Superior, Michigan, Huron, Erie, and Ontario within the United States and those streams entering the St. Lawrence River within the United States. This includes essentially all of the State of Michigan, except for approximately 23 square miles of Gogebic County, Michigan, and portions of Minnesota, Wisconsin, Illinois, Indiana, Ohio, Pennsylvania, and New York. It encompasses a land area of approximately 118,000 square miles and a water area of 61,000 square miles.

For purposes of delineating and describing the power industry in the Basin, the Power Region has been established to conform with the hydrologic boundary. The overall Power Region has been subdivided into the 15 river basin groups utilized in the Framework Study. In order to define the area more precisely, the data of each river basin group have been further subdivided in the Addendum as follows: River Basin Group 2.2 (Lake Michigan Southwest) into 2.2, Wisconsin, 2.2, Illinois, and 2.2, Indiana and Michigan; River Basin Group 2.4 (Lake Michigan Northeast) into 2.4, Lower Michigan, and 2.4, Upper Michigan; River Basin Group 3.1 (Lake Huron North) into 3.1, Lower Michigan, and 3.1, Upper Michigan. Figure 10-1 shows the delineation of the Power Region.

1.2 Power Region Economy

Electric energy consumption is related primarily to population and use of natural resources. Increases in population result in greater use of electricity in the home, in commercial establishments, and recreational and other activities. A rising standard of living

results in increased use per customer. Utilization of available natural resources imposes increased electric energy demands in the mine, factory, mill, and on the farm. Thus, the availability of economical electric energy is a key element in the economy of a region and, in turn, the power industry is directly affected by the economic climate.

Although the Basin occupies only four percent of the U.S. land area, it contains about 15 percent of the country's population. The bulk of this population is concentrated in major urban centers scattered along the southern shores of the Great Lakes. In 1970, the population of the Basin was about 29.1 million.

Because of the abundance of water available for use in manufacturing and in the transportation of raw materials, the Great Lakes Basin has developed into a major manufacturing area. Durable goods industries are important, especially those involved with the production and utilization of steel. At the present time approximately one-half of the country's steel is produced in this Region.

In the southern portion of the Basin, manufacturing is the main economic factor. Manufacturing centers in this area include Chicago, Detroit, Cleveland, Milwaukee, and the Calumet area of Indiana. Major manufacturing centers also exist in Buffalo, Rochester, and Syracuse. However, the eastern portion of the Region derives additional economic benefit from dairy farms, fruit orchards, and vacation resorts. The northern parts of Minnesota, Wisconsin, and Michigan comprise the northern section of the Basin. These areas are characterized by rather sparse population and only limited manufacturing. Much of this area's economy is dependent on lumbering, mining, and recreation.

A complete description of the Region's economy is included in Appendix 19, *Economic and Demographic Studies*.

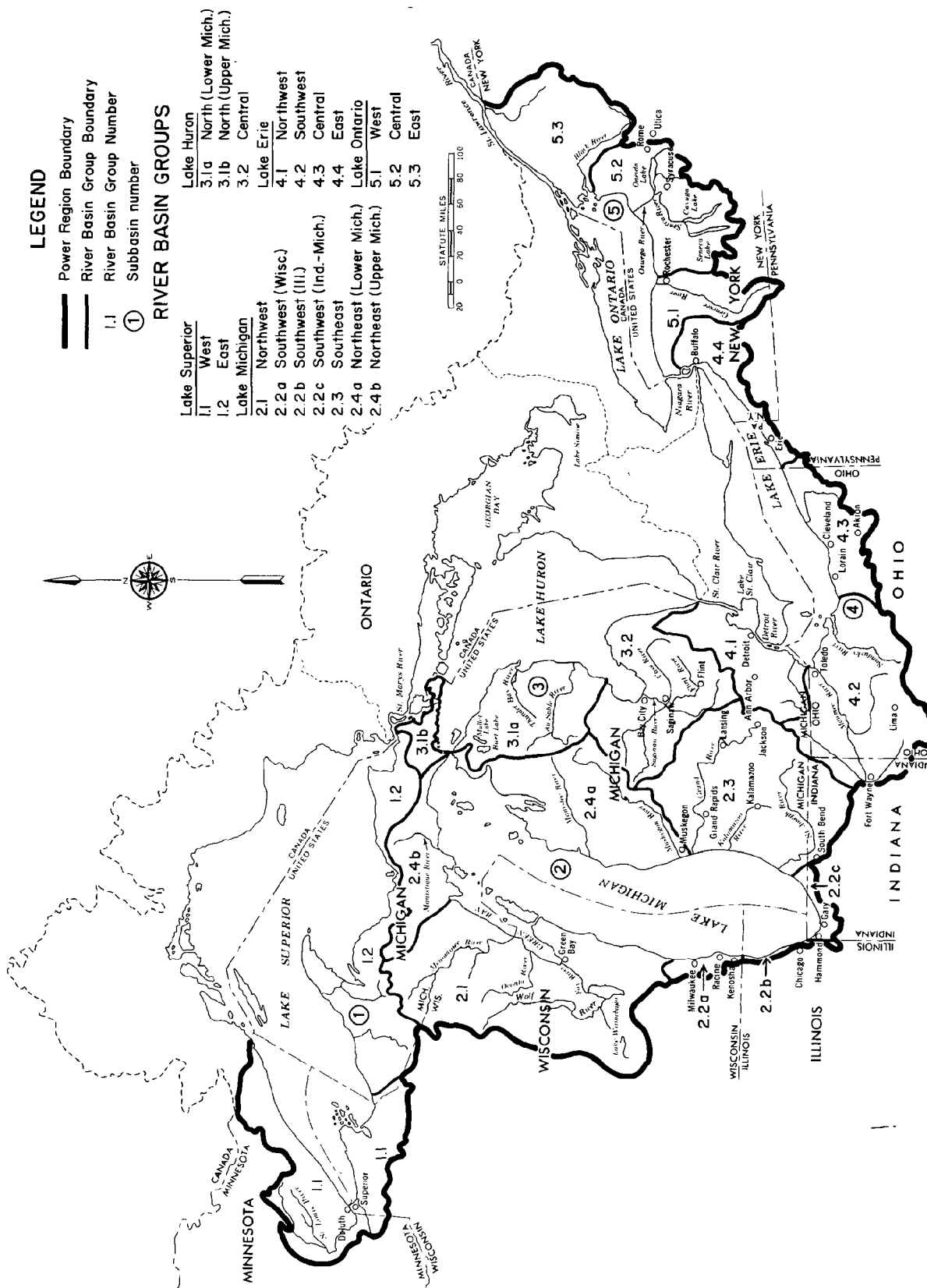


FIGURE 10-1 Great Lakes Basin Power Region Map

Section 2

ELECTRIC POWER INDUSTRY CHARACTERISTICS

2.1 Organization of the Electric Power Industry

The Great Lakes Basin Power Region in 1970 contained all or part of 356 electric utility systems. Of these, 63 were investor-owned systems, 233 were municipal and other publicly owned systems, 59 were cooperative systems, and one was a Federal system. The composition of the 1970 power supply energy requirements is shown in Figure 10-2. Operation of some of the utilities extend outside of the study area, but only that portion of the load and capacity data of these utilities within the Great Lakes Basin Power Region boundary is included in this report. Data on the generating plants of two utilities located in Illinois on Lake Michigan are included in the tables regarding power supply and cooling water. However, the loads of these plants are not included in the load data tables because their loads are essentially located outside the Great Lakes Basin drainage area.

Investor-owned utilities comprise about 83 percent of the generating capacity and energy production, and 91 percent of the energy requirements. The remaining power supply and requirements are essentially those of municipal and other publicly owned systems.

About 36 percent of the 233 public systems, which for the most part are quite small, have generating equipment whose production is often supplemental by external purchases. The cooperative group is composed of 59 systems, of which 18 have some generating and transmission facilities, and 41 have only distribution facilities.

Recognition should be given to the nonutility supply which is composed almost entirely of industrial generation. In 1965, the nonutility generating capacity was approximately 3.2 million kilowatts, compared with the utility capacity of 25.0 million kilowatts. Nonutility generation was approximately 17.1 billion kilowatt hours. The 1970 nonutility data are not presently available. However, on a national basis the 1970 industrial self-generation amounted to about seven percent of the utility

generation. We estimated that this will decrease to 2.6 percent by 1990. Because of the small relative magnitude of the nonutility supply and the uncertainties of the future, this source of supply was not considered in the projected power supply utilized in this study. Appendix 6, *Water Supply—Municipal, Industrial, and Rural*, does consider the water supply required for self-sustained industrial generation.

In perspective, the electric power requirements of the Great Lakes Basin Power Region totaled 161.3 billion kilowatt hours in 1970, approximately 10.6 percent of the national total. The total generating capacity was 32.8 million kilowatts, 9.6 percent of the national total. The 1970 annual peak loads and energy requirements are shown in Table 10-1 by river basin group.

2.2 Power Planning Coordination

In order to effect an adequate supply of reliable, low-cost power, nine regional reliability councils and many local power groups have been organized throughout the nation. They coordinate in varying degrees the planning, construction, and operation of transmission and generating facilities of groups of utilities. The utilities in the Great Lakes Basin participate in five major regional organizations. Figure 10-3 shows the location of these groups.

The major utilities in the Lake Superior West river basin group are members of the Mid-Continent Area Reliability Coordination Agreement (MARCA). MARCA includes members from all segments of the power industry and is primarily a reliability coordination organization. The service areas of MARCA members include all or part of ten midwestern States from Montana to Wisconsin, and from Missouri to the Canadian border, and the Canadian Province of Manitoba. Within the same Basin region are the Mid-Continent Area Power Planner (MAPP) and the Upper Mississippi Valley Power Pool (UMVPP). These groups are concerned primarily with long-term planning

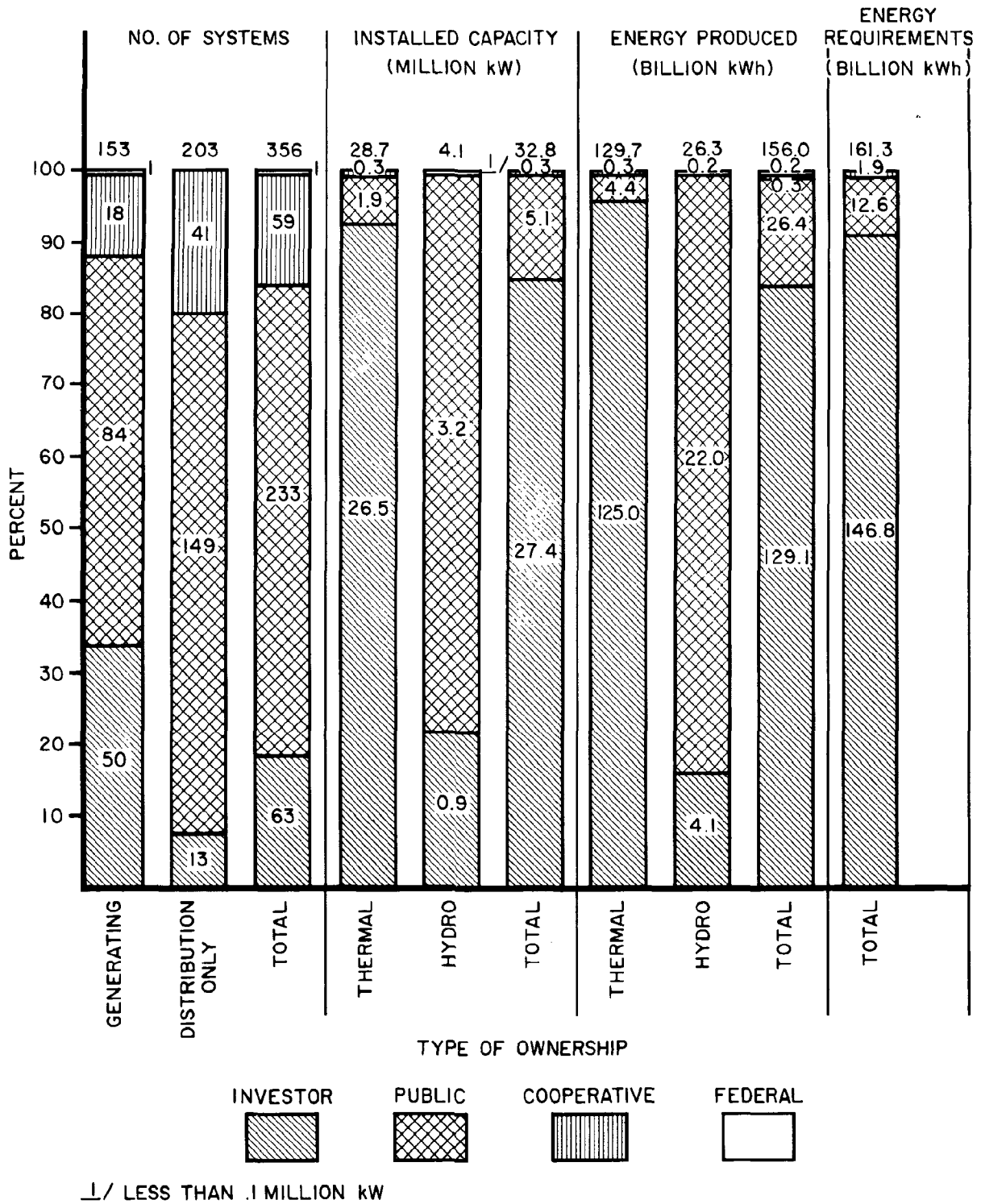


FIGURE 10-2 Composition of 1970 Power Supply and Requirements

TABLE 10-1 1970 Annual Peak Loads and Energy Requirements

River Basin Group	Annual Peak Load (MW)*	Annual Energy Requirements (million kWh)	Annual Load Factor** (%)
<u>Lake Superior</u>			
1.1 West	510	2,946	65.9
1.2 East	283	1,614	65.1
Subtotal	793***	4,560	65.6
<u>Lake Michigan</u>			
2.1 Northwest	1,248	7,581	69.3
2.2 Southwest	2,935	16,281	63.3
2.3 Southeast	2,896	16,268	64.1
2.4 Northeast	556	3,175	65.2
Subtotal	7,635***	43,305	64.7
<u>Lake Huron</u>			
3.1 North	270	1,392	58.9
3.2 Central	1,393	8,027	65.8
Subtotal	1,663***	9,419	64.7
<u>Lake Erie</u>			
4.1 Northwest	5,805	32,455	63.8
4.2 Southwest	2,583	16,460	72.7
4.3 Central	3,707	21,941	67.6
4.4 East	1,594	9,443	67.6
Subtotal	13,689***	80,299	67.0
<u>Lake Ontario</u>			
5.1 West	2,315	12,270	60.5
5.2 Central	1,079	6,582	69.6
5.3 East	770	4,868	72.2
Subtotal	4,164***	23,720	65.0
Total GLB	27,944***	161,303	65.9

* MW (megawatts) = 1,000 kilowatts (kW)

** Annual energy requirements divided by product of the annual peak load and the number of hours in the year.

$$LF = \frac{\text{Energy} \times 100}{\text{Peak} \times \text{No. hrs. in yr.}}$$

*** Non-coincident

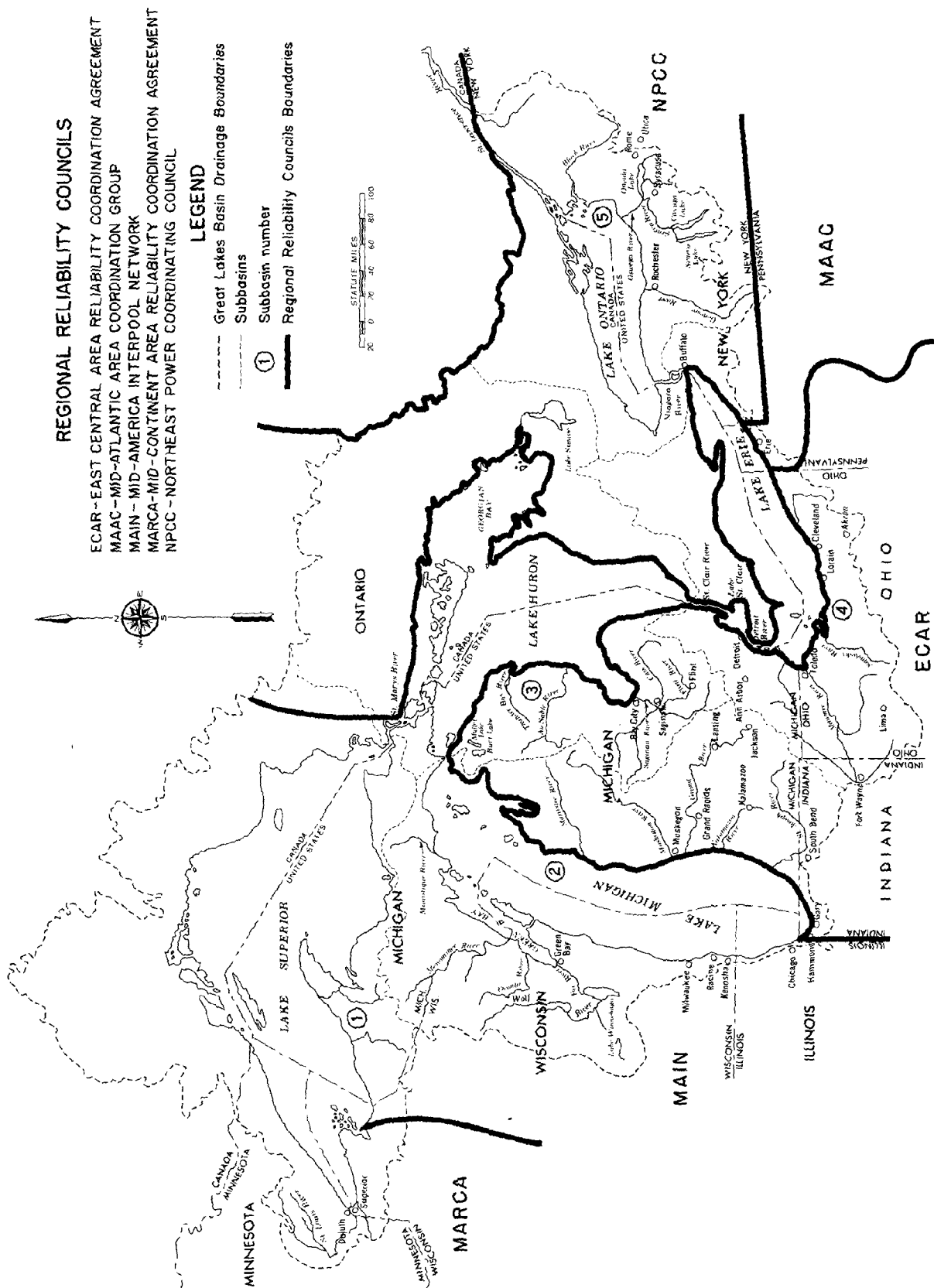


FIGURE 10-3 Great Lakes Basin Regional Reliability Councils

of power facilities and daily operations of the utilities in the area.

The coordinated electric systems in Wisconsin and Upper Michigan (western part of the Lake Michigan Northeast river basin group, the Lake Michigan Northwest, the Lake Superior East, and the western part of the Lake Michigan Southwest river basin groups) are members of the Mid-American Interpool Network (MAIN). The members of MAIN have a generating capacity of more than 40 million kilowatts and serve major portions of Illinois, Missouri, Iowa, Minnesota, Wisconsin, and Upper Michigan, and minor portions of eight additional States. A planning group in the area, known as the Wisconsin-Upper Michigan Systems, includes utilities in Eastern Wisconsin and the Upper Peninsula of Michigan. This group coordinates long-term planning of power facilities for the utility members.

Utilities on the eastern shore of Lake Michigan, the western shore of Lake Huron, and the southwestern shore of Lake Erie participate in the East Central Area Reliability Coordination Agreement (ECAR), which consists of 26 members in Michigan, Indiana, Ohio, Kentucky, West Virginia, Virginia, Maryland, and Pennsylvania. Coordinated power planning organizations within the region include: the Michigan Pool, consisting of two utilities in Michigan; the Central Area Power Coordination Group (CAPCO), consisting of five utilities in Ohio and Pennsylvania; the Kentucky-Indiana Pool (KIP), consisting of three utilities and one cooperative in Indiana and Kentucky; and Buckeye Power, Inc., consisting of 28 cooperatives in Ohio.

Utilities in the remainder of the Lake Erie area, all of the Lake Ontario area, the western shores of Lakes Superior and Huron, and the western reaches of the St. Lawrence River are members of the Northeast Power Coordinating Council (NPCC), a reliability coordination group of 20 utilities in New York, New England, and Ontario. Power pools serving the same area are the New York Power Pool (NYPP) for the utilities in New York, and the New England Power Exchange (NEPEX) for those in New England. Touching Lake Erie in Pennsylvania is a tiny sector of the Mid-Atlantic Area Coordination group (MAAC), which consists of 12 utilities in Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia. These same 12 utilities also constitute the Pennsylvania-New Jersey-Maryland Interconnection pool (PJM).

The electric systems in the Great Lakes Basin represent only a portion of the total sys-

tems involved in the aforementioned coordination groups. Because of their participation in these groups they are well coordinated with each other and with the systems outside the Great Lakes Basin in their day-to-day operations and in their long-range planning of electric power facilities. The advantages of coordinated planning and operation are obvious. Investment savings are effected by:

- (1) the reduction of generating capacity, reserve requirements for forced outages and scheduled maintenance
- (2) the use of larger, more efficient generating units
- (3) the utilization of seasonal load diversities among systems to reduce the total generating capacity required
- (4) avoidance of duplication of transmission facilities

Operational savings can be achieved by coordination of economy loading of available supply and reduced spinning reserves. This also helps to conserve our natural resources. Reliability of service is enhanced by coordination. For example, during an emergency, an electric system may acquire power from a number of interconnected systems through a regional transmission grid.

2.3 Generation

Steam plants using coal and gas as fuel (Figure 10-4) generate the major portion of electric energy in the Great Lakes Basin Power Region. Hydroelectric plants also contribute significantly to the power supply. There are numerous small diesel plants, but these account for only one percent of the total energy supply. The gas turbine is popular in some areas as a source of peaking and emergency power. This application may become important in the future. Table 10-2 lists the 1970 generating capacity installed in the Power Region and the energy produced by river basin group.

Energy and peak load requirements of the Great Lakes Basin Power Region for the year 1970 were determined by analysis of reports and service area maps filed with the Federal Power Commission (FPC) by electric utilities serving the Region. These requirements were 161,303 million kWh of energy and 27,944 MW of peak demand in 1970. Subtracting the energy requirements from the energy produced in the area indicates a net import of 5.3 billion kWh into the Power Region, or about 3.3 percent of the energy requirements. However,

in 1965 there was a net export from the Region of 1.0 billion kWh. Since the power transferred into and out of the Region is short-term power which will vary in direction of flow, the overall, long-term effect of power transfers is insignificant.

Thus, except for known future commitments (which are indicated in Section 4) the Great Lakes Basin Power Region is considered self-sufficient in projecting the future power supply capacity requirements.

TABLE 10-2 1970 Installed Generating Capacity and Energy Production

River Basin Group	Capacity in MW			Net Generation in million-kWh		
	Thermal	Hydro	Total	Thermal	Hydro	Total
Lake Superior						
1.1 West	404	88	492	1,920	451	2,371
1.2 East	255	42	297	1,412	174	1,586
Subtotal	659	130	789	3,332	625	3,957
Lake Michigan						
2.1 Northwest	1,560	150	1,710	4,648	712	5,360
2.2 Southwest	6,408	---	6,408	29,769	---	29,769
2.3 Southeast	2,333	36	2,369	8,870	125	8,995
2.4 Northeast	758	87	845	3,775	273	4,048
Subtotal	11,059	273	11,332	47,062	1,110	48,172
Lake Huron						
3.1 North	99	110	209	172	602	774
3.2 Central	1,608	10	1,618	7,340	36	7,376
Subtotal	1,707	120	1,827	7,512	638	8,150
Lake Erie						
4.1 Northwest	6,560	---	6,560	33,998	---	33,998
4.2 Southwest	1,282	---	1,282	4,994	---	4,994
4.3 Central	3,419	---	3,419	14,267	---	14,267
4.4 East	1,580	^a	1,580	7,765	2	7,767
Subtotal	12,841	---	12,841	61,024	2	61,026
Lake Ontario						
5.1 West	1,025	2,251	3,276	4,200	15,584	19,784
5.2 Central	1,453	86	1,539	6,574	298	6,872
5.3 East	1	1,207	1,208	---	8,017	8,017
Subtotal	2,479	3,544	6,023	10,774	23,899	34,673
Total GLB	28,745	4,067	32,812	129,704	26,274	155,978

^aLess than 1 MW

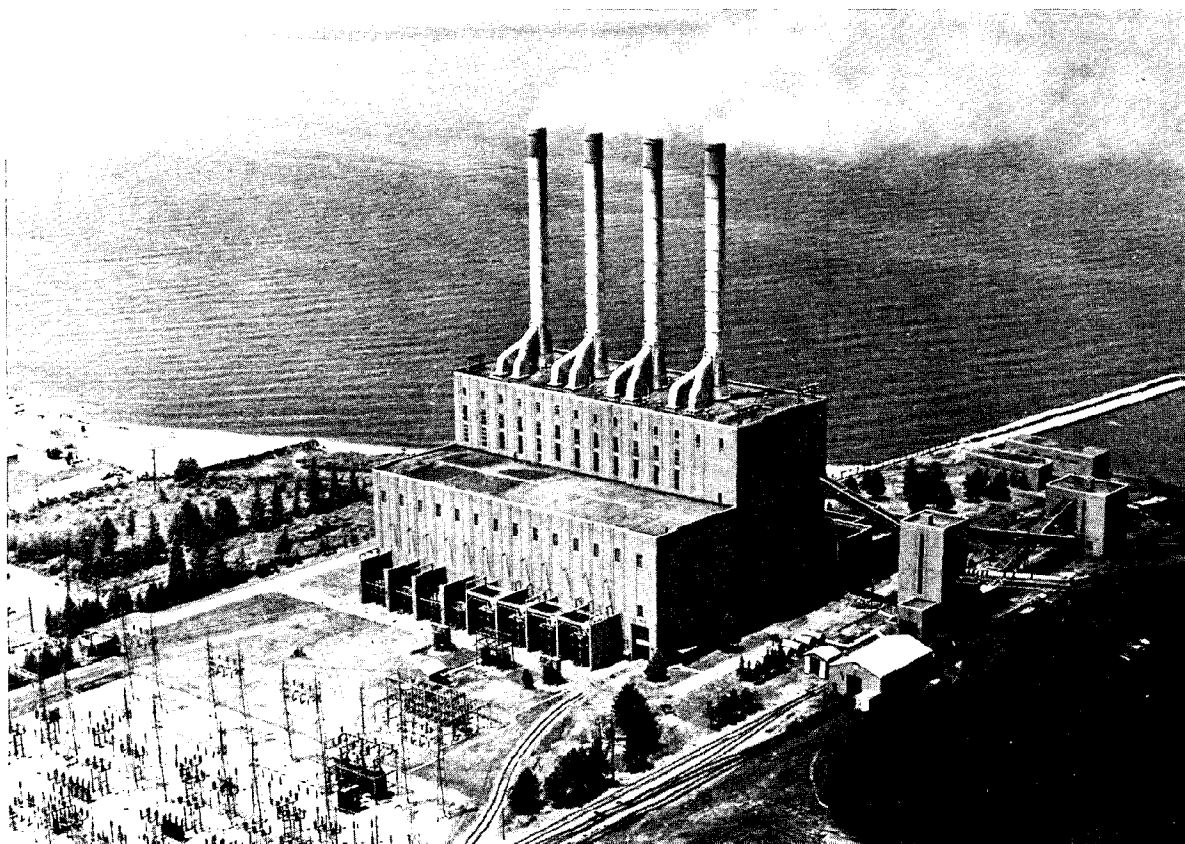


Photo courtesy of Niagara Mohawk Power Corporation

FIGURE 10-4 407,000 Kilowatt Fossil-Fueled Oswego Steam Station of the Niagara Mohawk Power Corporation

The steam-electric generating plants installed in 1970 contained 27.0 million kW of capacity and were fossil-fueled, except for about 1.8 million kW of nuclear capacity. However, recent developments in the nuclear power field indicate a trend toward nuclear plants as a major source of power in the near future (Figure 10-5). Approximately 16.8 million kW of existing and scheduled nuclear generating capacity are planned for installation in the Basin in the 1970s. These plants are listed in Table 10-3.

The hydroelectric plants in the Great Lakes Basin Power Region, as shown in Table 10-2, amounted to 4.1 million kW, accounted for 12 percent of the 1970 generating capacity, and produced 17 percent of the energy. This hydro capacity is concentrated mainly in river basin groups 5.1 and 5.3. The hydroelectric plants of the Power Authority of the State of New York (Figure 10-6), a State-owned utility, constitute the bulk of the hydroelectric supply, and

account for 76 percent of the total hydro capacity.

The thermal and hydroelectric generating plants of 10 MW and over installed in the Basin as of December 31, 1970, and their types of ownership, are listed in Table 10-4. Their general locations are shown in Figure 10-7.

2.4 Transmission

Transmission facilities of electric utilities perform several basic functions:

- (1) the transportation of bulk power supply (large amounts of power) from a source to a power consumer
- (2) emergency backup of interconnected electric systems in case of power disturbances
- (3) transfers of firm power between systems
- (4) interchange of economy power

These functions are accomplished by trans-

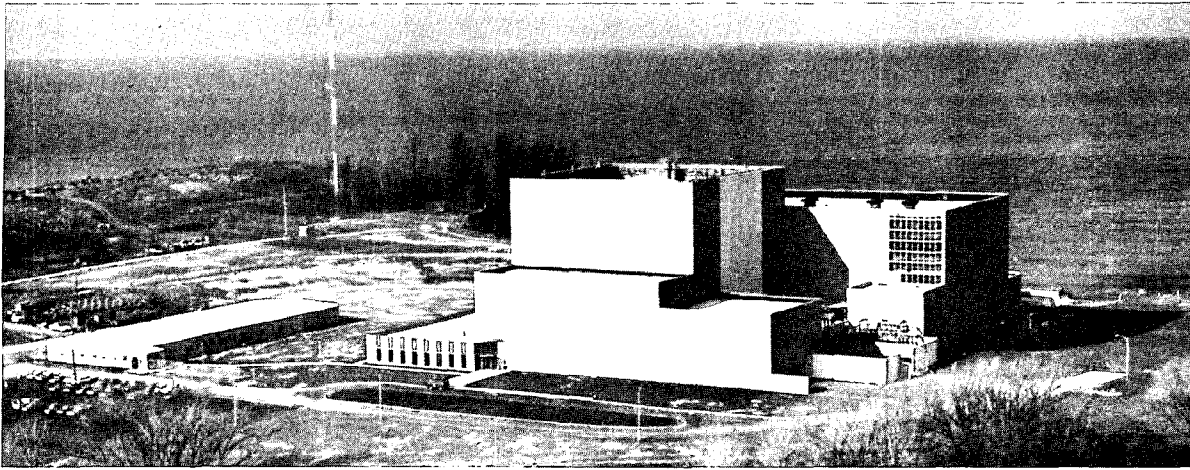


Photo courtesy of Rochester Gas and Electricity Corporation

FIGURE 10-5 517,000 Kilowatt Ginna Nuclear Plant. Completed recently by Rochester Gas and Electric Corporation on Lake Ontario fifteen miles east of Rochester, New York.

mission lines connecting generating sources, load centers within individual power systems, and by interconnecting the bulk power facilities of one electric system to the bulk power facilities of another system. Transmission systems below 345-kV have been developed to facilitate the movements of power within limited distances. Extra-high-voltage (EHV) systems, 345-kV and greater, are being constructed to permit the movements of larger amounts of power for greater distances. The EHV systems generally extend over a widespread region and interconnect with similar systems in adjacent regions. Consequently, the transmission facilities of the Great Lakes Basin need to be considered in relation to the overall developments in neighboring regions outside the Basin.

The electric utilities of the Great Lakes Basin are located in parts of three geographical regions which were utilized in updating the FPC National Power Survey: the West Central Region, the East Central Region, and the Northeast Region. In 1970 there were approximately 620 circuit miles of 230-kV transmission lines: 550 in the Northeast Region and 70 in the West Central Region. There were 1880 circuit miles of 345-kV lines, of which 480 were located within the Northeast Region, 1100 within the East Central Region, and 300 within the West Central Region.

An additional 3430 circuit miles of 345-kV is planned to be installed within the Power Region by 1980, of which 480, 2500, and 450 circuit miles are planned for the Northeast Region, East Central Region and West Central Re-

gions respectively. This would bring the total installed 345-kV lines to 5310 circuit miles in 1980.

Approximately 50 circuit miles of 500-kV lines in the West Central Region and 400 circuit miles of 765-kV lines in the East Central Region may be installed in the Power Region by 1980.

Additional lines are under consideration for 1990: 100 circuit miles of 230-kV in the West Central Region; 200 circuit miles of 345-kV in the East Central Region; 70 circuit miles in the West Central Region; 20 circuit miles of 500-kV in the West Central Region; and 360, 450, and 200 circuit miles of 765-kV lines in the Northeast, East Central, and West Central Regions respectively. The total circuit miles of each voltage classification considered for installation by 1990 is 720 of 230-kV; 5580 of 345-kV; 70 of 500-kV; and 1410 of 765-kV.

A discussion of the transmission facilities in each of the above FPC regions follows. Figure 10-8 shows the portion of the transmission system of each region within the Great Lakes Basin. It includes those systems existing in 1970 and those contemplated for 1980.

2.4.1 West Central Region

The major transmission system in the Great Lakes Basin portion of the West Central Region is part of a 345-kV transmission grid developed by the MAIN and MARCA regional power planning organizations for their upper midwest service areas. In the future, the grid

TABLE 10-3 Nuclear Steam-Electric Generating Plants in the Great Lakes Basin (Existing and Scheduled as of December 31, 1970)

System(s)	Plant	Location	Name- Plate Cap. (MW)	Cooling Water Source	Date in Serv.
Comm.Ed.Co.	Zion #1	Zion, Ill.	1,100	L.Mich.	5-72
	Zion #2	Zion, Ill.	1,100	L.Mich.	5-73
No.Ind.Pub.Srv.Co.	Bailly	Dunes Acres, Ind.	686	L.Mich.	2-76
Wis.Mich.Pwr.Co.& Wis.Elec.Pwr.Co.	Point Beach#1	Two Creeks, Wis.	524	L.Mich.	12-70
Wis.Pub.Serv.Co.)	Point Beach#2	Two Creeks, Wis.	524	L.Mich.	8-71
Wis.Pwr.&Lt.Co.) Madison G&E Co.)	Kewaunee	Kewaunee, Wis.	527	L.Mich.	6-72
Consumers Pwr.Co.	Big Rock Pt.	Charlevoix, Mich.	75	L.Mich.	1962
Consumers Pwr.Co.	Palisades #1	Covert Township, VanBuren Co., Mich.	812	L.Mich.	6-71
Consumers Pwr.Co.	Midland #1	Nr.Midland, Mich.	526	T.R.1/	11-75
Consumers Pwr.Co.	Midland #2	Nr.Midland, Mich.	855	T.R.1/	11-76
Ind.& Mich.El.Co.	D.C.Cook #1	Nr.Bridgman, Mich.	1,100	L.Mich.	3-73
	D.C.Cook #2	Nr.Bridgman, Mich.	1,100	L.Mich.	3-74
The Det.Ed.Co.	Enrico Fermi#1	Nr.Monroe, Mich.	70	L.Erie	1967
	Enrico Fermi#2	Nr.Monroe, Mich.	1,075	L.Erie	8-74
Toledo Ed.Co.& Cleve. Elec.Illum.Co.	Davis-Besse	Ottawa Co., Ohio	906	L.Erie	12-74
Roch.G& El.Corp.	Station 13 #1	Ontario, N.Y.	517	L.Ont.	7-70
Roch.G& El.Corp.	Station 13 #2	Ontario, N.Y.	1,000	L.Ont.	1979
N.Y.State E&G Corp.	Bell	Ludlowville, N.Y.	853	L.Cayuga	10-77
Niagara Mohawk Pwr.Corp.	Nine Mi.Pt.#1	Nr.Oswego, N.Y.	642	L.Ont.	12-69
Niagara Mohawk Pwr.Corp.	Nine Mi.Pt.#2	Nr.Oswego, N.Y.	875	L.Ont.	10-77
Niagara Mohawk Pwr.Corp.	Undecided	Undecided	1,100	L.Ont.	1979
Power Auth.of the St. of N.Y.	FitzPatrick	Nr.Oswego, N.Y.	850	L.Ont.	6-73
Total			16,817		

1/ Tittabawassee River

will completely link several major population centers both inside and outside the Great Lakes Basin: Chicago, Milwaukee, the Twin Cities, Sioux City, Omaha, Kansas City, Des Moines, the Quad-Cities (Davenport and Bettendorf, Iowa; and Rock Island and Moline, Illinois), and St. Louis. The Iron Range areas of northern Minnesota are linked by 230-kV lines with eastern North Dakota and the lignite mine-mouth plants in western North Dakota. Construction of these transmission facilities was completed in 1970.

The Chicago-Milwaukee-Twin Cities line is approximately 470 miles long and was completed in 1966. The line permits coordination among the three major utility groups in the area: the Upper Mississippi Valley Power Pool, the Eastern Wisconsin Utility group, and Commonwealth Edison Company.

Heavy concentrations of EHV facilities around St. Louis, Chicago, Milwaukee, and the Minneapolis-St. Paul areas are planned. In the Twin Cities area, a double circuit 345-kV loop was built around the metropolitan area,

TABLE 10-4 Generating Plants, Existing and Scheduled—10 Megawatts and Over (as of December 31, 1970)

No. & Name of Plant	MW Capacity & Type	Utility	No. & Name of Plant	MW Capacity & Type	Utility
1.1 Lake Superior West			2.4 Lake Michigan Northwest		
1 Aurora	116.1 St	MIPL	1 Advance	41.8 St	NOMC
2 Bay Front	82.2 St	LASD	2 Big Rock	75.0 Nu	COPR
3 Fond du Lac	12.0 Hy	MIPL	3 Cobb	510.5 St	COPR
4 Hibbard, M. L.	122.5 St	MIPL	4 Escanaba	23.0 St	UPPP
5 Hibbing	19.0 St	HIBB	5 Hardy	30.0 Hy	COPR
6 Thomson	67.4 Hy	MIPL	6 Hadenpyl	18.0 Hy	COPR
7 Virginia	17.5 St	VIRG	7 Johnson	10.1 IC	WOEL
8 Winslow	25.2 St	SUML	8 Ludington	1,872.0 PS*	COPR & DEEC
1.2 Lake Superior East			9 Straits	25.0 GT	COPR
1 Ishpeming	10.0 IC	CLCI	10 Tippy, C. W.	20.0 Hy	COPR
2 Marquette	15.8 IC	MARQ	11 Traverse City	35.0 St	TRAV
	13.5 St	MARQ			
	22.0 St*	MARQ	3.1 Lake Huron North		
3 Presque Isle	174.7 St	UPGC	1 Gaylord	90.6 GT	COPR
	170.0 St*	UPGC	2 Sault Ste. Marie	41.3 Hy	EDSE
4 Victoria	12.0 Hy	UPPP	3 St. Marys Falls	18.4 Hy	USAR
5 Warden, J. H.	18.8 St	UPPP	4 Tower	20.0 GT*	NOMC
2.1 Lake Michigan Northwest			3.2 Lake Huron Central		
1 Big Quinnesec Falls	19.5 Hy	WIMP	1 Harbor Beach	121.0 St	DEEC
2 Edgewater	480.0 St	WIPL & WIPS	2 Karn, D. E.	530.0 St	COPR
3 Kaukauna	23.4 CT	KAUK		615.0 St*	COPR
4 Kewaunee	527.0 Nu*	WIPS & MAGE	3 Midland	1,381.3 Nu*	COPR
5 Manitowoc	69.0 St	MANI	4 Oliver	13.8 IC	DEEC
6 Menasha	29.2 St	MENA	5 Saginaw River	147.0 St	COPR
7 Niagara	12.0 St	KICC	6 Thetford	149.0 GT	COPR
8 Peavy Falls	15.0 Hy	WIMP	7 Weadock, J. C.	614.5 St	COPR
9 Point Beach	20.0 CT	WIMP		20.6 GT	COPR
10 Point Beach	523.8 Nu	WIEP & WIMP	8 Wilmet	13.8 IC	DEEC
11 Pulliam	523.8 Nu*	WIMP			
	392.5 St	WIPS	4.1 Lake Erie Northwest		
2.2 Lake Michigan Southwest			1 Beacon	27.8 St	DEEC
1 Bailly	615.6 St	NOIP	2 Conners Creek	596.6 St	DEEC
	33.9 GT*	NOIP	3 Dayton	10.0 IC	DEEC
2 Bailly	686.0 Nu*	NOIP	4 Delray	391.0 St	DEEC
3 Commerce Street B	35.0 St	WIEP	5 Fermi, Enrico	88.0 St	DEEC
4 East Wells Street	15.0 St	WIEP		62.0 GT	DEEC
5 Lakeside	310.8 St	WIEP	6 Fermi, Enrico #2	70.0 Nu	DEEC
	36.0 GT	WIEP	7 Hancock	1,075.0 Nu*	DEEC
6 Michigan City	215.0 St	NOIP		160.3 CT	DEEC
	521.0 St*	NOIP	8 Marysville	308.0 St	DEEC
7 Mitchell, Dean H.	529.4 St	NOIP	9 Minstersky	175.0 St	DETR
	52.2 CT	NOIP	10 Monroe	3,000.0 St*	DEEC
8 North Oak Creek	500.0 St	WIEP		13.8 IC	DEEC
9 Port Washington	400.0 St	WIEP	11 Pennsalt	37.0 St	DEEC
	19.6 GT	WIEP	12 Placid	27.5 IC	DEEC
10 South Oak Creek	1,191.6 St	WIEP	13 Northeast	62.0 CT	DEEC
	19.6 GT	WIEP	14 River Rouge	933.2 St	DEEC
11 State Line	972.0 St	COED		11.0 IC	DEEC
12 Valley	272.0 St	WIEP	15 St. Clair	1,905.0 St	DEEC
13 Waukegan	1,043.0 St	COEC		18.6 GT	DEEC
	113.0 CT	COEC	16 Slocum	13.8 IC	DEEC
14 Winnetka	25.5 St	WINK	17 Superior	62.0 GT	DEEC
15 Zion	2,200.0 Nu*	COEC	18 Trenton Channel	1,093.5 St	DEEC
			19 Whiting, J. R.	325.0 St	COPR
2.3 Lake Michigan Southeast				15.3 GT	COPR
1 Campbell, J. H.	650.0 St	COPR	20 Wyandotte	41.5 St	WYAN
	20.6 IC	COPR		23.0 GT	WYAN
2 Coldwater	10.5 St	COLD	21 Wyandotte North	54.1 St	DEEC
3 Colfax	13.8 IC	DEEC	22 Wyandotte South	18.5 St	DEEC
4 Cook	2,200.0 Nu*	INME	4.2 Lake Erie Southwest		
5 DeYoung, J.	82.5 St	HOLL	1 Acme	337.0 St	TOEC
6 Delta	160.0 St*	LABW	2 Bay Shore	639.5 St	TOEC
7 Eckert	386.0 St	LABW		16.0 GT	TOEC
8 Elm Street	30.0 St	COPR	3 Bryan	21.5 CT	BRAN
9 Grand Haven	20.0 St	GRHA	4 Celina	12.5 St	CELLI
	19.8 IC	GRHA	5 Davis-Besse	906.0 Nu*	TOEC
10 Hillsdale	11.0 IC	HILD	6 Lawton Park	40.0 St	FOWA
11 Kalamazoo	20.0 St	COPR		15.0 GT	FOWA
12 Michigan State U.	25.0 St	MISU	7 Napoleon	23.5 St	NAPO
13 Morrow, B. E.	186.0 St	COPR	8 Richland	45.0 GT	TOEC
	36.0 GT	COPR	9 St. Marys	22.0 St	SAMA
14 Ottawa Street	81.5 St	LABW	10 Stryker	19.0 GT	TOEC
15 Palisades	811.7 Nu*	COPR	11 Water Street	10.0 St	TOEC
16 Twin Branch	394.0 St	INME	12 Woodlawn Avenue	31.3 St	NORW
17 Wealthy Street	20.0 St	COPR	13 Woodcock	42.5 St	OHFC

TABLE 10-4(continued) Generating Plants, Existing and Scheduled—10 Megawatts and Over (as of December 31, 1970)

No. & Name of Plant	MW Capacity & Type	Utility
4.2 Lake Erie Central		
1 Ashtabula	456.0 St	CLEI
2 Avon Lake	1,275.0 St	CLEI
3 Collinswood	17.8 GT	CLEV
4 East 53rd Street	50.0 St	CLEV
5 Eastlake	577.0 St	CLEI
	625.0 St*	CLEI
6 Edgewater	174.9 St	OHEC
7 Gorge	87.5 St	OHEC
8 Lake Road	172.5 St	CLEV
9 Lake Shore	514.0 St	CLEI
10 Oberlin	12.9 St	OBOW
11 Painesville	38.0 St	PAIN
	25.0 St*	PAIN
12 West 41st Street	35.6 GT	CLEV
4.4 Lake Erie East		
1 Dunkirk	628.0 St	NIMP
2 Front Street	118.8 St	PEEC
3 Huntley	828.0 St	NIMP
5.1 Lake Ontario West		
1 Lewiston Reservoir	240.0 PS	POAS
2 Moses, Robert-Niagara	1,950.0 Hy	POAS
3 Station No. 3	206.2 St	ROGE
	19.0 GT	ROGE
4 Station No. 5	38.3 Hy	ROGE
5 Station No. 7	252.6 St	ROGE
6 Station No. 9	19.0 GT	ROGE
7 Station No. 13	517.1 Nu	ROGE
	1,000.0 Nu*	ROGE
5.2 Lake Ontario Central		
1 Bell	853.3 Nu*	NEYE
2 Bennetts Bridge	26.8 Hy	NIMP
3 FitzPatrick, J.A.	849.7 Nu*	POAS
4 Greenidge	160.0 St	NEYE
5 Milliken	270.0 St	NEYE
6 Nine Mile Point	641.8 Nu	NIMP
	875.0 Nu*	NIMP
7 Oswego	376.0 St	NIMP
	875.0 St*	NIMP
Undecided	1,100.0 Nu*	NIMP
5.3 Lake Ontario East		
1 Blake	14.4 Hy	NIMP
2 Brown Falls	15.0 Hy	NIMP
3 Colton	30.0 Hy	NIMP
4 Deferiet	10.8 Hy	NIMP
5 Five Falls	22.5 Hy	NIMP
6 Moses, Robert-St.Lawrence	912.0 Hy	POAS
7 Rainbow	22.5 Hy	NIMP
8 Soft Maple	15.0 Hy	NIMP
9 South Colton	19.4 Hy	NIMP
10 Stark	22.5 Hy	NIMP

Utility Abbreviations		
Code	Type	Utility
BRAN	MUN	Bryan, Ohio
CELI	MUN	Celina, Ohio
CLCI	PRI	Cleveland-Cliffs Iron Co.
CLEI	PRI	Cleveland Electric Illuminating Co., The
CLEV	MUN	Cleveland, Ohio
COEC	PRI	Commonwealth Edison Co.
COED	PRI	Commonwealth Edison Co. of Indiana, Inc.
COLD	MUN	Coldwater, Michigan
COPR	PRI	Consumers Power Co.
DEEC	PRI	Detroit Edison Co., The
DETU	MUN	Detroit, Michigan
EDSE	PRI	Edison Sault Electric Co.
FOWA	MUN	Fort Wayne, Indiana
GRHA	MUN	Grand Haven, Michigan
HIBB	MUN	Hibbing, Minnesota
HILD	MUN	Hillsdale, Michigan
HOLL	MUN	Holland, Michigan
INME	PRI	Indiana & Michigan Electric Co.
KAUK	MUN	Kaukauna, Wisconsin
KICC	PRI	Kimberly Clark Corp.
LABW	MUN	Lansing, Michigan
LASD	PRI	Lake Superior District Power Co.
MAGE	PRI	Madison Gas & Electric Co.
MANI	MUN	Manitowoc, Wisconsin
MARQ	MUN	Marquette, Michigan
MENA	MUN	Menasha, Wisconsin
MIPL	PRI	Minnesota Power & Light Co.
MISU	STATE	Michigan State University
NAPO	MUN	Napoleon, Ohio
NEYE	PRI	New York State Electric and Gas Corp.
NIMP	PRI	Niagara Mohawk Power Corp.
NOIP	PRI	Northern Indiana Public Service Co.
NOMC	COOP	Northern Michigan Electric Coop.
NORW	MUN	Norwalk, Ohio
OBOW	MUN	Oberlin, Ohio
OHEC	PRI	Ohio Edison Co.
OHPC	PRI	Ohio Power Co.
PAIN	MUN	Painesville
PEEC	PRI	Pennsylvania Electric Co.
POAS	STATE	Power Authority of the State of New York
ROGE	PRI	Rochester Gas & Electric Corp.
SAMA	MUN	Saint Marys, Ohio
SUWL	PRI	Superior Water, Light and Power Co.
TRAV	MUN	Traverse City, Michigan
UPGC	PRI	Upper Peninsula Generating Co.
UPFP	PRI	Upper Peninsula Power Co.
USAR	FED	U. S. Army
VIRG	MUN	Virginia, Minnesota
WIEP	PRI	Wisconsin Electric Power Co.
WIMP	PRI	Wisconsin Michigan Power Co.
WINK	MUN	Winnetka, Illinois
WITI	PRI	Wisconsin Power & Light Co.
WIPS	PRI	Wisconsin Public Service Corp.
WVEL	PRI	Wolverine Electric Coop.
WYAN	MUN	Wyandotte, Michigan

Type of Utility	
PRI	Private
MUN	Municipal
FED	Federal
COOP	Cooperative
STATE	State

Type of Capacity	
GT	Gas Turbine
Hy	Hydro
IC	Internal Combustion
Nu	Nuclear Steam
PS	Pumped Storage
St	Fossil Steam

* Scheduled for operation after 1970

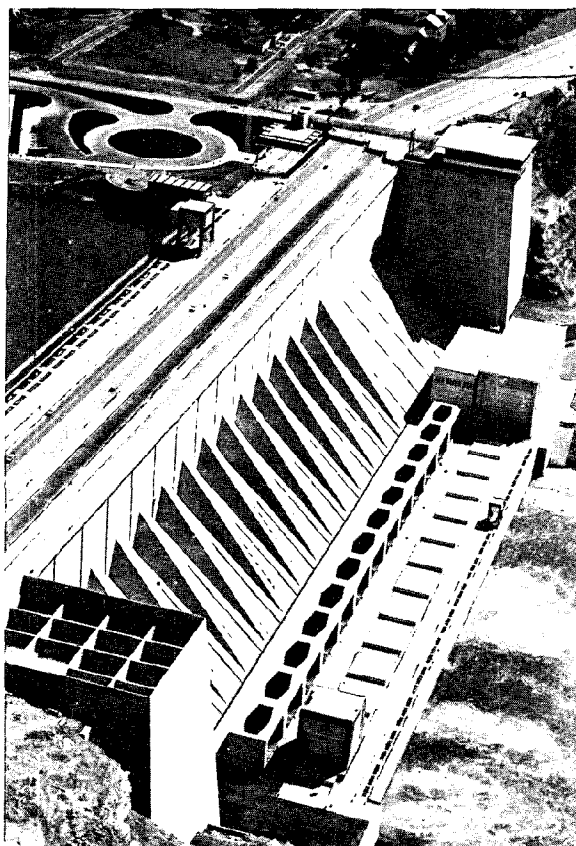


Photo courtesy of the Power Authority of the State of New York

FIGURE 10-6 The Robert Moses Niagara Power Plant of the Power Authority of the State of New York. The plant, which is located on the Niagara River Gorge approximately $4\frac{1}{2}$ miles downstream from the Falls, houses thirteen 150,000 kilowatt generators driven by 200,000 horsepower hydraulic turbines.

and completed in 1968. These local EHV concentrations are being reinforced by EHV ties between the areas. A 345-kV tie between the Chicago and St. Louis areas was completed in 1969. In 1971, two 345-kV circuits extending westward from the Chicago area to the Quad-Cities area, and a 345-kV circuit from Quad-Cities which ties into the 345-kV circuit extending from St. Louis to Minneapolis were completed. Also in 1971, a 765-kV system in the East Central Region was installed. Later additions will extend this line around to the northwestern part of the Chicago metropolitan area and west to Quad-Cities Station by 1980. The total EHV transmission circuit mileage in the West Central Region existing in 1970 and estimated to be in service by 1980 and

1990 is given by voltage class in Table 10-5.

The completion of the above transmission system should provide for adequate power movements between the systems within the Great Lakes Basin as well as to adjacent regions. It also provides sufficient low cost and reliable power to satisfy the needs of the Basin within the West Central Region.

TABLE 10-5 West Central Region Circuit Mileage

Voltage kV	Circuit Miles		
	1970	1980	1990
230	5800	6620	6850
345	2970	6340	10600
500	----	1250	2400
765	----	570	2170

2.4.2 East Central Region

Both the electric loads and the generating plants in the East Central Region are widely distributed. Consequently, the transmission pattern which has developed provides regional coverage through a multiplicity of interconnections between the systems, rather than radial connections required by point source distributions of power. This has resulted in a highly developed transmission system of EHV lines which includes approximately 5000 circuit miles of 345-kV, 600 circuit miles of 500-kV and 500 circuit miles of 765-kV. These lines overlay an extensive network of 138-kV with lesser amounts of 230-kV and 161-kV lines throughout the region. There are also many interconnections with systems in adjacent regions at voltages as high as 500-kV. Contemplated additions to the existing transmission system between 1971-1980 are: 2100 circuit miles of 765-kV, of which 1200 was to be installed by 1972; 600 circuit miles of 500-kV; and 4800 circuit miles of 345-kV. The total transmission system in 1980 will consist of about 13,500 circuit miles of lines 345-kV and above. The 765-kV lines (Figure 10-9) will form a transmission loop in Ohio, Indiana, Kentucky, and West Virginia, and extend into Virginia, Michigan, and Illinois. The 500-kV will be concentrated generally in the eastern part of the region. The 345-kV will expand into Kentucky and southern Indiana, and join Toledo and Cleveland. Other ties to areas contiguous to the East Central Region are contemplated: three 765-kV ties to Illinois; addi-

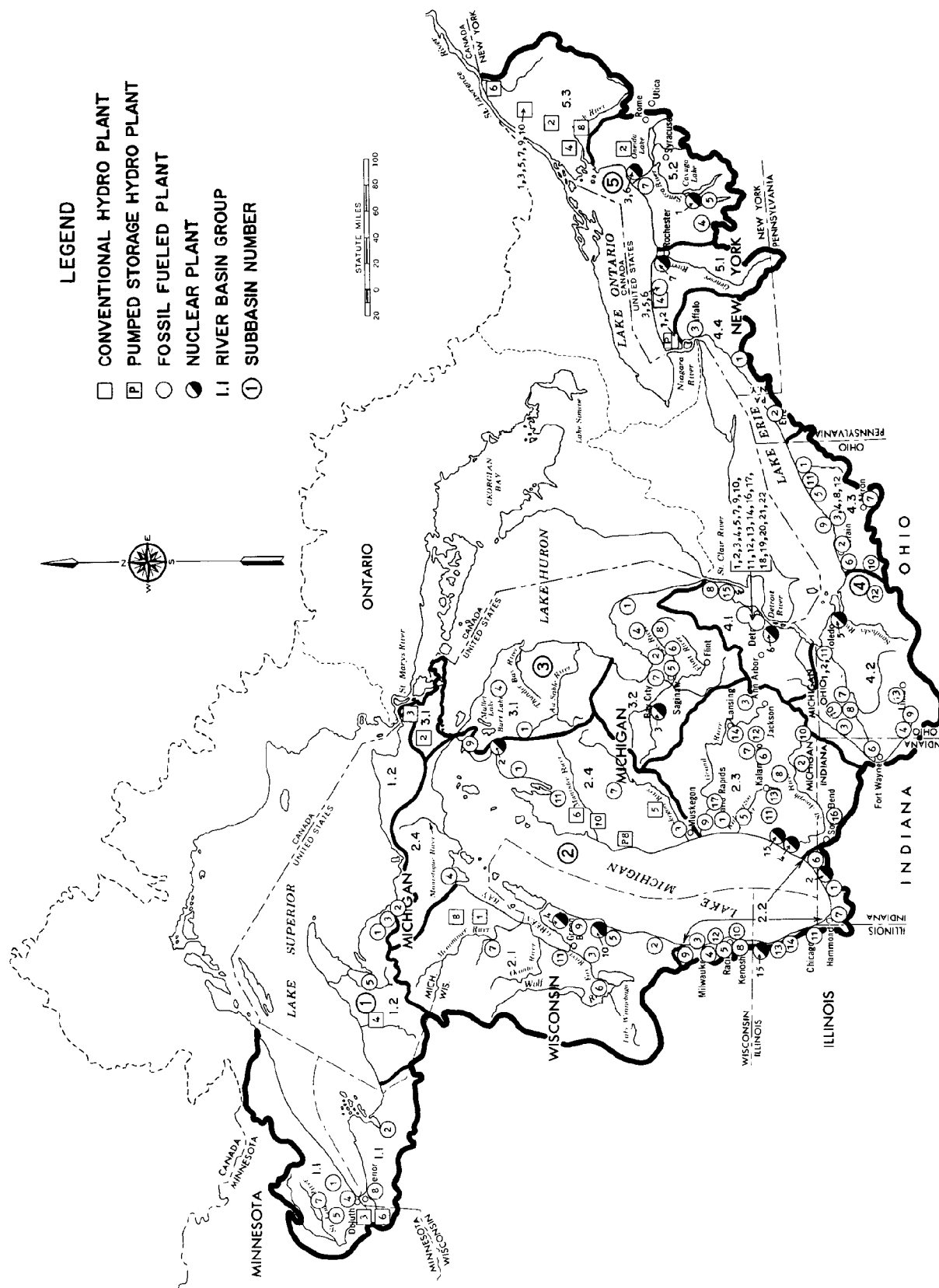


FIGURE 10-7 Great Lakes Basin Generating Plants 10 MW and Over, Existing and Scheduled (as of December 31, 1970)

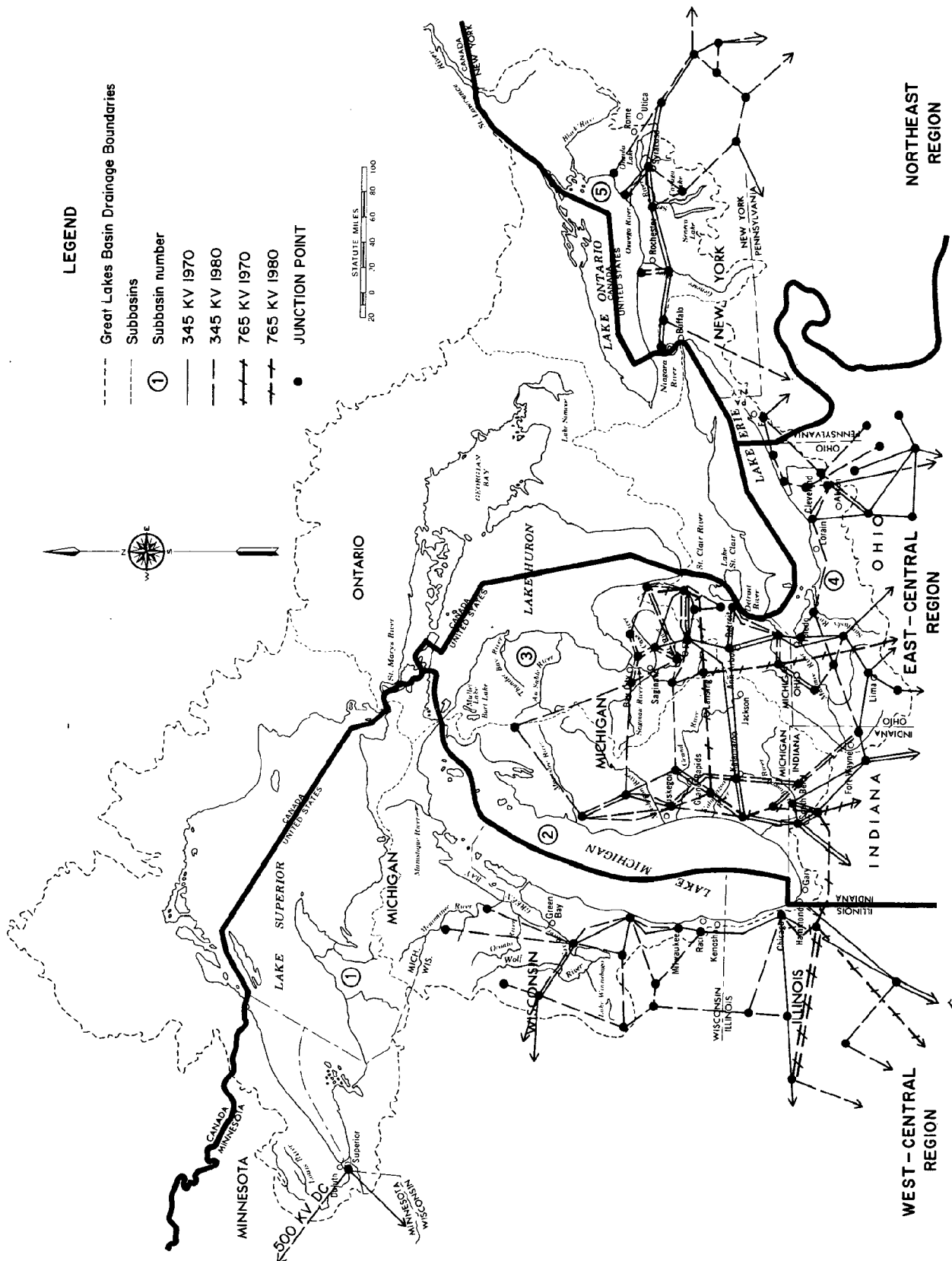


FIGURE 10-8 Great Lakes Basin Power Region EHV Transmission Lines, Existing and Planned

tional ties with the Tennessee Valley Authority (TVA); and EHV lines to the CARVA power pool in the Carolinas and Virginias, and the PJM pool in Pennsylvania, New Jersey, and Maryland.

During the period 1981–1990, the expansion of the foregoing EHV system tentatively includes an additional 1200 circuit miles of 765-kV, 300 circuit miles of 500-kV, and 1800 circuit miles of 345-kV. All told, by 1990 there will exist in the East Central Region approximately 17,000 circuit miles of EHV transmission lines, of which 4000 will be 765-kV. Additional ties with adjacent regions are also being considered to strengthen interregional interconnections.

2.4.3 Northeast Region

The principal EHV levels in the Northeast are 345-kV in New England and New York and 500-kV on the Pennsylvania-New Jersey-Maryland Interconnection (PJM). The systems are well established and are continually being added to and strengthened. Underlying the EHV grid is an extensive network of 230-kV, 138-kV, and 115-kV lines. The New York Power Pool is interconnected with each of the other two coordination areas (New England and PJM) comprising the Northeast Region at 345-kV, 230-kV, and 115-kV. Additional EHV inter-ties are either under construction or planned.

When the initial phase of the New England 345-kV network is completed in the early 1970s, the principal components will consist of: a major loop together with several sub-loops in the populous States of Connecticut, Massachusetts, and Rhode Island and in southern New Hampshire and Vermont; a double circuit from Scobie Substation in New Hampshire to the Maine Yankee nuclear plant northeast of Portland, Maine; a single circuit tie with New Brunswick; and a second interconnection with the New York Power Pool at New Scotland southwest of Albany, New York.

In New York, the existing 345-kV backbone (double circuit, except for a single circuit section between Utica and Albany) running from Buffalo to Syracuse to Albany to New York City will be looped along the southern part of the State to provide greater flexibility, reliability, and capacity and to facilitate major inter-ties with PJM. In addition a second 345-kV interconnection will be made from the Buffalo area to PJM in northeastern Pennsylvania. Principal ties with Ontario Hydro

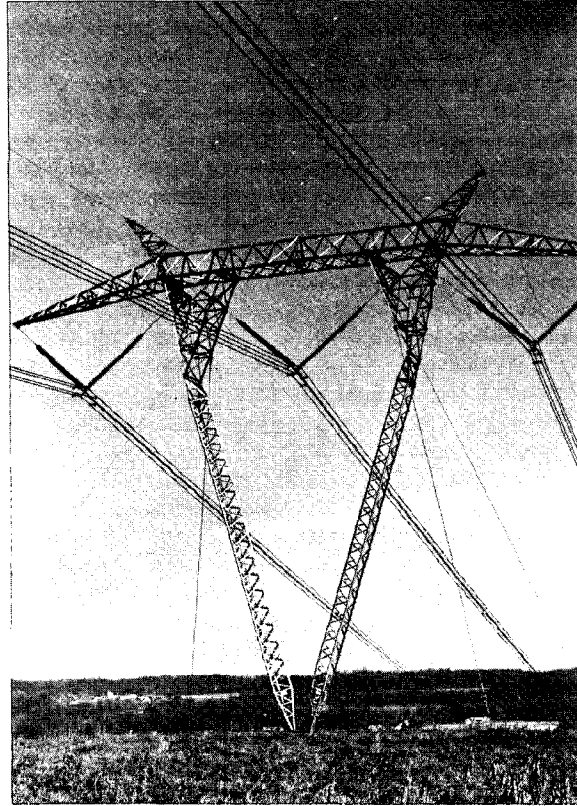


Photo courtesy of American Electric Power System

FIGURE 10-9 American Electric Power System's 765 kV Transmission Network. It will extend 1,250 miles over parts of seven States when initial grid is completed in 1973.

(Canada) are two 230-kV circuits at Niagara Falls and a single circuit at the St. Lawrence Project, Massena, New York.

Only a small portion of PJM in the vicinity of Erie, Pennsylvania, is in the Great Lakes Basin. There is a 230-kV tie with New York running from Erie to Dunkirk to the Buffalo area. In Erie, PJM also has a 345-kV tie with the Cleveland Electric Illuminating Company. In addition PJM is interconnected with the Allegheny Power System of the East Central Area Reliability (ECAR) group.

Looking ahead, the Northeast Regional Advisory Committee expects the introduction of 765-kV in New England and New York by 1990. This will be interconnected with the ECAR 765-kV system in the vicinity of Erie, Pennsylvania, and in effect will represent an extension of the latter which is now under construction. The 765-kV New York system will also be interconnected with PJM's 500-kV grid.

Section 3

HYDROELECTRIC POWER

3.1 Present State

In 1970 hydroelectric plants located in the Great Lakes Basin totaled 4,067 MW, or 12 percent of the Basin's total installed capacity. During 1970 these plants generated 26.3 billion kWh of electric energy.

Many of the more than 200 hydroelectric developments in the Basin are small, often less than 1000 kW in size. In 1970 there were only 23 conventional hydroelectric plants and one pumped-storage plant with installed capacities over 10 MW. Table 10-6 lists these plants.

In addition to the plants in the table, there are 474.2 MW of hydroelectric capacity in the Great Lakes Basin in plants of less than 10 MW. It is apparent from an examination of the table that River Basin Groups 5.1 and 5.3 are the only areas with a significant hydroelectric supply, 3312 MW or 81 percent of the Basin total. The three New York Power Authority (POAS) plants alone account for 3,102 MW. In 1970 the two POAS conventional stations produced 21.3 billion kWh, or approximately 81 percent of all the hydro generation in the Basin at a capacity factor of 85 percent. Plant factor of the remaining hydro capacity in 1970 was 47 percent.

The storage of the upper Great Lakes and the natural regulation which this affords, together with the controlled outflows of Lake Ontario in accordance with the plan of regulation approved by the International Joint Commission (IJC), make the flows of the St. Lawrence that are usable for power uniform. IJC has jurisdiction over boundary waters of Canada and the United States. Accordingly, the St. Lawrence-Robert Moses Power Plant operates at a very high capacity factor. Its capacity variations are attributed largely to variations of flow from month to month as required by the plan of regulation, and to certain specified departures of the hourly flows from the weekly regulated flows. This permits the power output to be varied a small amount to accommodate the daily peak load requirements of the system.

The Power Authority's Niagara Project consists of the Robert Moses Niagara Power Plant and the Lewiston Pumped Storage Plant. By working these plants together, it is possible to effectively utilize the flows available from the Niagara River for power. The 1950 Treaty between the United States and Canada concerning Niagara Project power diversions provided that during the hours 8 a.m. to 10 p.m., April 1 to September 15, and 8 a.m. to 8 p.m., September 16 through October 31, at least 100,000 cubic feet per second (cfs) must be allowed to flow over the Falls. At all other times the flow over the Falls may be reduced to no less than 50,000 cfs. In order to use the larger nighttime flows available under the Treaty for power diversions, it was necessary to provide the storage reservoir facilities. At night when power requirements are small, some of the available water is pumped into the Lewiston Pumped Storage reservoir. The following day when peak power demands are large, stored water is released through the Lewiston units which are then functioning as turbine generators. The water which they release augments daytime diversions from the Niagara River for use at the Robert Moses Niagara Power Plant. In this manner the output from the project can be varied from relatively small amounts at night to full machine capability during the peak load hours.

The principal structures of the Robert Moses-St. Lawrence Power Project are in the former International Rapids Section creating the power pool known as Lake St. Lawrence, and providing the channel by which ocean vessels enter the Great Lakes System. In addition, these structures regulate Lake Ontario levels and outflows. Since April 1960, water releases through the St. Lawrence Project have been prescribed by a plan or regulation designed by the IJC to meet the requirements of upstream and downstream riparian and navigation interests and the power entities. Operations prescribed by the plan of regulation are continuously monitored by the International St. Lawrence River Board of Control to insure compliance with the objectives of

TABLE 10-6 Hydroelectric Plants in Service as of December 31, 1970 (10 megawatts and over)

Plant Name	Owner	Installed Capacity (MW)	River Basin Group	State	River
Fond du Lac	MIPL	12.0	1.1	Minn.	St. Louis
Thomson	MIPL	67.4	1.1	Minn.	St. Louis
Victoria	UPPP	12.0	1.2	Mich.	W.Br. Ontonagon
Big Quinnesec Falls	WIMP	19.5	2.1	Mich.	Menominee
Peavy Falls	WIMP	15.0	2.1	Mich.	Michigan
Hardy	COPR	30.0	2.4	Mich.	Muskegon
Hodenpyl	COPR	18.0	2.4	Mich.	Manistee
Tippy, C. W.	COPR	20.0	2.4	Mich.	Manistee
St. Marys Falls	USAR	18.4	3.1	Mich.	St. Marys
Sault Ste. Marie	EDSE	41.3	3.1	Mich.	St. Marys
Lewiston Reservoir*	POAS	240.0	5.1	N.Y.	Niagara
Moses, Robert-Niagara	POAS	1,950.0	5.1	N.Y.	Niagara
Station No. 5	ROGE	38.3	5.1	N.Y.	Genesee
Bennetts Bridge	NIMP	26.8	5.2	N.Y.	Salmon
Blake	NIMP	14.4	5.3	N.Y.	Raquette
Brown Falls	NIMP	15.0	5.3	N.Y.	E.Br. Oswegatchie
Colton	NIMP	30.0	5.3	N.Y.	Raquette
Deferiet	NIMP	10.8	5.3	N.Y.	Black
Five Falls	NIMP	22.5	5.3	N.Y.	Raquette
Moses, Robert-St. Lawrence	POAS	912.0	5.3	N.Y.	St. Lawrence
Rainbow	NIMP	22.5	5.3	N.Y.	Raquette
Soft Maple	NIMP	15.0	5.3	N.Y.	Beaver
South Colton	NIMP	19.4	5.3	N.Y.	Raquette
Stark	NIMP	22.5	5.3	N.Y.	Raquette
Subtotal		3,592.8			
Miscellaneous (under 10 megawatts)		474.2			
TOTAL GLB		4,067.0			

*Pumped Storage

Ownership Code

COPR Consumers Power Co.

EDSE Edison Sault Electric Co.

MIPL Minnesota Power & Light Co.

NIMP Niagara Mohawk Power Corp.

POAS Power Authority of the State of New York

ROGE Rochester Gas & Electric Corp.

UPPP Upper Peninsula Power Co.

USAR U.S. Army

WIMP Wisconsin Michigan Power Co.

regulation established by the IJC. The Robert Moses-Robert H. Saunders Power Dam extends 3,300 feet across the river from Barnhart Island in New York to Cornwall, Ontario and contains 32 turbine generator units, 16 on each side of the international boundary. The Robert Moses and Robert H. Saunders Plants each have a rated installed capacity of 912,000 kW.

The first year during which POAS was able to fully and efficiently utilize all of the United States' share of the waters of the Niagara and St. Lawrence Rivers was in 1963. Power was first generated at the St. Lawrence plant in 1958 and at Niagara early in 1961. Although the St. Lawrence installation was first operated at near capacity during the summer of 1959, advantages resulting from the interconnection and joint operation of the two plants were not fully realized until the Niagara facility and the transmission tieline were almost completed.

Periods of low levels on the Great Lakes can result in a reduced energy production at the Niagara and St. Lawrence plants. Low water supplies in 1963 resulted in a reduction of energy production at Niagara from a normal 13 billion kWh to a total of 10.8 billion kWh and reduction at the St. Lawrence plant from a normal 6.5 billion kWh to 5.6 billion kWh. The flow of water in 1963 was the third lowest since records of flow were established in 1860.

Because it is a public agency, POAS has a substantial preferential customer load. In addition, residential customers of private utilities in New York, who are within economical transmission distance of the POAS projects, share in the benefits of this low-cost power. The legislation and Federal Power Commission licenses, which authorize the construction and operation of these plants, provided for the allocation of specified quantities of project power to other States. The Public Service Board of the State of Vermont has contracted for 100 MW and 50 MW from the St. Lawrence and Niagara projects, respectively. Allegheny Electric Cooperative, Inc., a group of 14 distribution co-ops in Pennsylvania, is allocated 100 MW from the Niagara Falls project.

Since completion of POAS's St. Lawrence project in 1958 and two Niagara Falls plants in 1962, the Authority's responsibilities in matters of power supply in New York have been enlarged to include nuclear and pumped storage within the limitations set forth in the recent legislation conferring this authority.

Currently under construction are the James A. FitzPatrick nuclear plant (850 MW) on Lake Ontario near Oswego and the FPC-licensed Blenheim-Gilboa 1,000 MW pumped-storage project southwest of Albany in the Hudson River Basin outside the Power Region. As the needs of New York dictate, POAS will continue to develop other potential pumped storage sites and expand the State's nuclear capability. However, unlike the out-of-State allocations written into the licenses of POAS's first two projects because of their international character, power from any of its future developments is reserved for the people of New York.

Additional descriptions of the existing hydroelectric projects are included in Appendix 11, *Levels and Flows*.

3.2 Federal Licensing of Hydroelectric Projects

The FPC's licensing authority for hydroelectric plants dates back to the Federal Water Power Act of 1920, which is now Part I of the Federal Power Act. Part I empowers the FPC to issue licenses for periods not exceeding 50 years to citizens, corporations, States, and municipalities authorizing the construction, operation, and maintenance of water power projects on navigable waterways, on streams, or on public lands or reservations of the United States. If any of these projects affects interstate commerce, Congress has jurisdiction. The Commission may also issue licenses to non-Federal interests for the purpose of utilizing surplus water or water power from a government dam. An important provision of the Federal Power Act is the requirement that any project, before it is licensed, must, in the judgment of the Commission, be best adapted to a comprehensive plan for the development and utilization of the water resources of the river basin.

When applications for licenses or license amendments are received, the Commission requests comments on the proposals from Federal, State, and local agencies with specific interests and responsibilities for resource development and conservation. The Commission evaluates each proposed project for safety, adequacy, economic feasibility, and adaptability to a comprehensive plan of development. Hearings are held, either upon request or upon the Commission's own motion, to consider all relevant factors involved in the

licensing action. Pursuant to existing statutes, the orders and actions of the Commission may be appealed to the courts.

Licenses issued by the Commission impose a number of standard requirements relative to the construction and operation of projects. These requirements are intended to assure optimum development of project sites and conservation of resources. Normally, each license also contains special conditions applicable to the particular project. Applicants must submit plans for Commission approval showing the planned use of project facilities for recreational uses and for the protection and enhancement of fish and wildlife resources affected by the project.

The planning, construction, and operation of hydroelectric projects are increasingly affected by other water uses and needs. There is an increasing demand for water resource developments to provide municipal and industrial water supply, water quality control, and water-based recreation, in addition to the need for power, flood control, navigation, and irrigation. These demands make it essential that water resources projects be undertaken as parts of long-range comprehensive plans of development. Thus, an important consideration in planning water resources projects which may include hydroelectric power is the coordination of the needs and demands of all appropriate water uses.

As of January 1, 1970, there were 110 utility hydroelectric plants containing 3,838,810 kW of capacity under Federal Power Commission licenses or licenses applied for in the Great Lakes Basin. In addition there is currently under construction near Ludington, Michigan, a pumped-storage development of maximum capacity of 1,872,000 kW which is scheduled to be completed during 1973. These plants are listed in Table 10-7.

3.3 Recapture or Relicensing of Hydroelectric Power Projects

In addition to the original licensing of non-Federal water power projects located on lands or waterways subject to Federal jurisdiction, the Commission is charged with the responsibility of reexamining these projects at the end of their license period.

If, after a comprehensive review of the project, the Commission determines that it should be relicensed, it will so order. However, any Federal department or agency that recommends takeover may file a motion requesting

a stay of the license order. Upon filing such a motion, the license order automatically will be stayed for two years from the date of issuance to permit presentation of the case to Congress. If by the expiration of the two-year stay the Congress has not acted, the new license will become effective.

If the Commission, after notice and opportunity for hearing, concludes upon departmental recommendation, the proposal of any party, or its own motion, that a project should be taken over by the United States, it will forward its findings and recommendations to Congress. A determination of takeover of a project would ultimately be made by Congress through enactment of appropriate legislation.

Also, when the licensee does not wish to continue power operations and the Commission judges that conversion of the project to a non-power use will best serve comprehensive development of the affected lands and waterways, the FPC is authorized to issue a license for that purpose. The nonpower license will be temporary and will continue only until a State, municipal, interstate, or another Federal agency assumes regulatory supervision of the lands and facilities included in the non-power license. This will assure that there will be no gap in regulatory supervision.

In examining a project for relicensing, a full exploration of all factors bearing on comprehensive development is made. Among those factors are multiple use of projects, hydraulic and electric coordination of the project with other projects and systems, water quality control, recreational development, fish and wildlife conservation, development of aesthetic values, and preservation of historical properties and archeological sites.

Each year the Commission publishes in its annual report and in the Federal Register a table of licenses expiring within five years following their publication. There are presently four hydroelectric developments in the Great Lakes Basin covered by licenses that will expire before 1976. These developments, with a total installation of 30,144 kW, are included in Table 10-7.

3.4 Potential Conventional Hydroelectric Power

The Federal Power Commission staff maintains an inventory of undeveloped hydroelectric sites, based principally on river basin surveys and project investigations. The river

TABLE 10-7 Utility Hydroelectric Generating Plants in the Great Lakes Basin Licensed by or Having Applications Pending before the Federal Power Commission as of January 1, 1970

- EXISTING -

L.P. No.	State	River	River Basin Group	Plant Name	Installed Capacity (kilowatts)	Licensee	Date of License Expiration
2360 Minn.		St.Louis	1.1	Fond du Lac	12,000	Minn.Pwr.& Lt.Co.	Appd. For
		St.Louis	1.1	Thomson	67,350	Minn.Pwr.& Lt.Co.	Appd. For
		St.Louis	1.1	Scanlon	1,600	Minn.Pwr.& Lt.Co.	Appd. For
		St.Louis	1.1	Knife Falls	2,400	Minn.Pwr.& Lt.Co.	Appd. For
2444 Wis.		White	1.1	White River	1,000	L.Sup.Dis.Pwr.Co.	12/31/93
2564 Wis.		Iron River	1.1	Orienta Falls	800	L.Sup.Dis.Pwr.Co.	12/31/93
2587 Wis.		Montreal	1.1	Superior Falls	1,800	L.Sup.Dis.Pwr.Co.	12/31/93
2610 Mich.		Montreal	1.1	Saxon Falls	1,250	L.Sup.Dis.Pwr.Co.	12/31/89
				Subtotal	88,200		
2382 Mich.		W.Br.Onto- nagon	1.2	Victoria	12,000	Upper Pen.Pwr.Co.	Appd. For
2402 Mich.		Sturgeon	1.2	Prickett	2,200	Upper Pen.Pwr.Co.	12/31/93
2589 Mich.		Dead	1.2	Development No.1	1,000	City of Marquette	Appd. For
		Dead	1.2	Development No.2	3,200	City of Marquette	Appd. For
		Dead	1.2	Development No.3	700	City of Marquette	Appd. For
				Subtotal	19,100		
710 Wis.		Wolf	2.1	Shawano	700	Wis.Pwr.& Lt.Co.	7/19/77
1510 Wis.		Fox	2.1	Kaukauna	4,800	Kaukauna El.& Wtr. Depts.	3/31/89
1759 Mich.		Menominee	2.1	Twin Falls	6,144	Wis.Mich.Pwr.Co.	6/30/70
		Michigamme	2.1	Peavy Falls	15,000	Wis.Mich.Pwr.Co.	6/30/70
		Michigamme	2.1	Ways Dam	1,800	Wis.Mich.Pwr.Co.	6/30/70
1980 Mich.		Menominee	2.1	Big Quinnesec	16,000	Wis.Mich.Pwr.Co.	2/28/98
		Menominee	2.1	Quinnesec Falls	3,530	Wis.Mich.Pwr.Co.	2/28/98
1981 Wis.		Oconto	2.1	Stiles	1,000	Oconto Elec.Coop.	2/29/2000
2072 Mich.		Paint	2.1	Lower Paint	100	Wis.Mich.Pwr.Co.	12/31/2001
2073 Mich.		Michigamme	2.1	Michigamme Falls	9,600	Wis.Mich.Pwr.Co.	10/31/2001
2074 Mich.		Michigamme	2.1	Hemlock Falls	2,800	Wis.Mich.Pwr.Co.	10/31/2001
2131 Mich.		Menominee	2.1	Kingsford	7,200	Wis.Mich.Pwr.Co.	6/30/74
2357 Mich.		Menominee	2.1	White Rapids	8,000	Wis.Mich.Pwr.Co.	12/31/93
2394 Mich.		Menominee	2.1	Chalk Hill	7,800	Wis.Mich.Pwr.Co.	6/30/93
2431 Wis.		Brule	2.1	Brule Island	5,335	Wis.Mich.Pwr.Co.	12/31/93
2433 Mich.		Menominee	2.1	Grand Rapids	7,020	Wis.Pub.Ser.Corp.	12/31/93
2464 Wis.		Red	2.1	Weed Dam	630	Gresham Wtr. & El.Plt.	6/30/2015
2471 Mich.		Sturgeon	2.1	Sturgeon River	800	Wis.Mich.Pwr.Co.	12/31/93
2484 Wis.		Red	2.1	Gresham	275	Gresham Wtr. & El.Plt.	Appd. For
2486 Wis.		Pine	2.1	Pine River	3,600	Wis.Mich.Pwr.Co.	12/31/93
2522 Wis.		Peshtigo	2.1	Johnson Falls	3,520	Wis.Pub.Ser.Corp.	12/31/93
2523 Wis.		Oconto	2.1	Oconto Falls	1,320	Wis.Mich.Pwr.Co.	12/31/93
2525 Wis.		Peshtigo	2.1	Caldron Falls	6,400	Wis.Pub.Ser.Corp.	12/31/93
2546 Wis.		Peshtigo	2.1	Sandstone Rapids	3,840	Wis.Pub.Ser.Corp.	12/31/93
2550 Wis.		Waupaca	2.1	Weyauwega	400	Wis.Mich.Pwr.Co.	12/31/93
2560 Wis.		Peshtigo	2.1	Potato Rapids	1,380	Wis.Pub.Ser.Corp.	12/31/93

TABLE 10-7(continued) Utility Hydroelectric Generating Plants in the Great Lakes Basin Licensed by or Having Applications Pending before the Federal Power Commission as of January 1, 1970

- EXISTING -

L.P. No.	State	River	River Basin Group	Plant Name	Installed Capacity (kilowatts)	Licensee	Date of License Expiration
2581 Wis.		Peshtigo	2.1	Peshtigo	584	Wis.Pub.Ser.Corp.	12/31/93
2588 Wis.		Fox	2.1	Little Chute	3,300	Kaukauna El.& Wtr. Depts.	Appd. For
2595 Wis.		Peshtigo	2.1	High Falls	7,000	Wis.Pub.Ser.Corp.	Appd. For
2677 Wis.		Fox	2.1	Badger	5,600	Kaukauna El.& Wtr. Depts.	Appd. For
		Fox	2.1	Croche	2,400	Kaukauna El.& Wtr. Depts.	Appd. For
Subtotal					137,878		
401 Mich.		St.Joseph	2.3	Mottville	1,680	Mich.Pwr.Co.	2/24/76
785 Mich.		Kalamazoo	2.3	Calkins Bridge	2,550	Consumers Pwr.Co.	4/10/80
2551 Mich.		St.Joseph	2.3	Buchanan	4,104	Ind.& Mich.El.Co.	Appd. For
2566 Mich.		Grand	2.3	Webber	3,250	Consumers Pwr.Co.	Appd. For
2579 Ind.		St.Joseph	2.3	Twin Branch	7,260	Ind.& Mich.El.Co.	Appd. For
2651 Ind.		St.Joseph	2.3	Elkhart	3,440	Ind.& Mich.El.Co.	Appd. For
Subtotal					22,284		
2451 Mich.		Muskegon	2.4	Rogers	6,000	Consumers Pwr.Co.	12/31/93
2452 Mich.		Muskegon	2.4	Hardy	30,000	Consumers Pwr.Co.	12/31/93
2468 Mich.		Muskegon	2.4	Croton	8,849	Consumers Pwr.Co.	12/31/93
2580 Mich.		Manistee	2.4	C.W.Tippy	20,000	Consumers Pwr.Co.	Appd. For
2599 Mich.		Manistee	2.4	Hodenpyl	18,000	Consumers Pwr.Co.	Appd. For
Subtotal					82,849		
2404 Mich.		Thunder Bay	3.1	Four Mile Dam	1,800	Alpena Pwr.Co.	12/31/93
Mich.		Thunder Bay	3.1	Ninth Street	1,050	Alpena Pwr.Co.	12/31/93
Mich.		Thunder Bay	3.1	Norway Point	4,000	Alpena Pwr.Co.	12/31/93
2419 Mich.		Thunder Bay	3.1	Hillman	250	Alpena Pwr.Co.	12/31/93
2436 Mich.		Au Sable	3.1	Footte	9,000	Consumers Pwr.Co.	12/31/93
2447 Mich.		Au Sable	3.1	Alcona	8,000	Consumers Pwr.Co.	12/31/93
2448 Mich.		Au Sable	3.1	Mio	5,000	Consumers Pwr.Co.	Appd. For
2449 Mich.		Au Sable	3.1	Loud	4,000	Consumers Pwr.Co.	12/31/93
2450 Mich.		Au Sable	3.1	Cooke	9,000	Consumers Pwr.Co.	12/31/93
2453 Mich.		Au Sable	3.1	Five Channels	6,000	Consumers Pwr.Co.	12/31/93
Subtotal					48,100		
2216 N.Y.		Niagara	5.1	Lewiston Reservoir*	240,000	Pwr.Auth.St.N.Y.	8/31/2007
		Niagara	5.1	Robert Moses- Niagara	1,950,000	Pwr.Auth.St.N.Y.	8/31/2007
2424 N.Y.		Barge Canal	5.1	Hydraulic Race	4,687	Niagara Mohawk Pwr.Corp.	6/30/91
2582 N.Y.		Genesee	5.1	Station No.2	6,500	Rochester G&E Corp.	12/31/93
2583 N.Y.		Genesee	5.1	Station No.5	38,250	Rochester G&E Corp.	12/31/93
2584 N.Y.		Genesee	5.1	Station No.26	3,000	Rochester G&E Corp.	12/31/93

TABLE 10-7(continued) Utility Hydroelectric Generating Plants in the Great Lakes Basin Licensed by or Having Applications Pending before the Federal Power Commission as of January 1, 1970

- EXISTING -

L.P. No.	State	River	River Basin Group	Plant Name	Installed Capacity (kilowatts)	Licensee	Date of License Expiration
2596 N.Y.		Genesee	5.1	Station No.160	340	Rochester G&E Corp.	Appd. For
2667 N.Y.		Oak Orchard Creek	5.1	Glenwood	1,500	Niagara Mohawk Pwr.Corp.	Appd. For
		Oak Orchard Creek	5.1	Waterport	4,650	Niagara Mohawk Pwr.Corp.	Appd. For
				Subtotal	2,248,927		
2438 N.Y.		Seneca	5.2	Seneca Falls	8,000	NY St.E&G Corp.	12/31/93
		Seneca Canal	5.2	Waterloo	1,920	NY St.E&G Corp.	12/31/93
2474 N.Y.		Oswego	5.2	Fulton	1,250	Niagara Mohawk Pwr.Corp.	12/31/87
		Oswego	5.2	Granby 1 & 2	3,722	Niagara Mohawk Pwr.Corp.	12/31/87
		Oswego	5.2	Minetto	8,000	Niagara Mohawk Pwr.Corp.	12/31/87
		Oswego	5.2	Varick	8,800	Niagara Mohawk Pwr.Corp.	12/31/87
				Subtotal	31,692		
2000 N.Y.		St.Lawrence	5.3	Robert Moses- St.Lawrence	912,000	Pwr.Auth.St.N.Y.	10/31/2003
2084 N.Y.		Raquette	5.3	Blake Falls	14,400	Niagara Mohawk Pwr.Corp.	1/31/2002
		Raquette	5.3	Five Falls	22,500	Niagara Mohawk Pwr.Corp.	1/31/2002
		Raquette	5.3	Rainbow Falls	22,500	Niagara Mohawk Pwr.Corp.	1/31/2002
		Raquette	5.3	South Colton	19,350	Niagara Mohawk Pwr.Corp.	1/31/2002
		Raquette	5.3	Stark	22,500	Niagara Mohawk Pwr.Corp.	1/31/2002
2320 N.Y.		Raquette	5.3	Colton	29,520	Niagara Mohawk Pwr.Corp.	12/31/93
		Raquette	5.3	Hannawa	7,200	Niagara Mohawk Pwr.Corp.	12/31/93
		Raquette	5.3	Higley	4,480	Niagara Mohawk Pwr.Corp.	12/31/93
		Raquette	5.3	Sugar Island	4,800	Niagara Mohawk Pwr.Corp.	12/31/93
2330 N.Y.		Raquette	5.3	Norfolk	4,500	Niagara Mohawk Pwr.Corp.	12/31/93
		Raquette	5.3	East Norfolk	3,000	Niagara Mohawk Pwr.Corp.	12/31/93
		Raquette	5.3	Norwood	2,000	Niagara Mohawk Pwr.Corp.	12/31/93
		Raquette	5.3	Raymondville	2,000	Niagara Mohawk Pwr.Corp.	12/31/93

TABLE 10-7(continued) Utility Hydroelectric Generating Plants in the Great Lakes Basin Licensed by or Having Applications Pending before the Federal Power Commission as of January 1, 1970

- EXISTING -

L.P. No.	State	River	River Basin Group	Plant Name	Installed Capacity (kilowatts)	Licensee	Date of License Expiration
2442	N.Y.	Black	5.3	Watertown	5,400	Watertown Mu.E.Dept.	12/31/93
2538	N.Y.	Black	5.3	Beebee Island	8,000	Beebee Island Corp.	12/31/93
2569	N.Y.	Black	5.3	Black River	6,000	Niagara Mohawk Pwr.Corp.	Appd. For
		Black	5.3	Deferiet	10,800	Niagara Mohawk Pwr.Corp.	Appd. For
		Black	5.3	Herrings	5,400	Niagara Mohawk Pwr.Corp.	Appd. For
		Black	5.3	Kamargo	5,400	Niagara Mohawk Pwr.Corp.	Appd. For
		Black	5.3	Sewalls Island	2,000	Niagara Mohawk Pwr.Corp.	Appd. For
2645	N.Y.	Beaver	5.3	Belfort	1,800	Niagara Mohawk Pwr.Corp.	Appd. For
		Beaver	5.3	Eagle	6,050	Niagara Mohawk Pwr.Corp.	Appd. For
		Beaver	5.3	Effley	2,960	Niagara Mohawk Pwr.Corp.	Appd. For
		Beaver	5.3	Elmer	1,500	Niagara Mohawk Pwr.Corp.	Appd. For
		Beaver	5.3	Moshier	8,000	Niagara Mohawk Pwr.Corp.	Appd. For
		Beaver	5.3	Soft Maple	15,000	Niagara Mohawk Pwr.Corp.	Appd. For
		Beaver	5.3	Taylorville	4,500	Niagara Mohawk Pwr.Corp.	Appd. For
2664	N.Y.	Beaver	5.3	High Falls	4,800	Niagara Mohawk Pwr.Corp.	Appd. For
2695	N.Y.	Black	5.3	Dexter	1,420	Dexter Hydro-E. Corp.	Appd. For
Subtotal					1,159,780		
Total GLB					3,838,810		

- UNDER CONSTRUCTION -

2680	Mich.		2.4	Ludington*	1,872,000 ¹	Consumers Pwr.Co.& Detroit Edison Co.	6/30/2019
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* Pumped Storage

¹ Nominally rated at 1,620,000 kW

basin studies encompass those by Federal agencies, various Federal-State entities operating under the aegis of the Water Resources Council, and others, including water resources appraisal studies undertaken by the Commission staff. Project investigations include those by Federal and State agencies, electric utilities, and others, including studies submitted with applications for licenses and preliminary permits.

The estimates of undeveloped water power include projects for which studies have indicated both engineering and economic feasibility, and projects at sites where physical conditions indicate engineering feasibility, but for which detailed studies of economic feasibility have not been made. The estimates are subject to revision either by increase or decrease as additional information concerning streamflow, reservoir sites, costs, and other pertinent factors becomes available. Taken as a whole, the estimates serve to indicate from a long-range view the overall conventional water power potential of the United States available for possible future development.

Economic and other factors may preclude the development of many of these potential hydroelectric sites in the Great Lakes Basin. Detailed analyses of projects at sites having relatively small power potentials frequently result in adverse findings of economic justification. Also, in many cases, highways, industrial plants, and other facilities have been constructed in areas that would be needed for reservoirs of potential projects. The cost of relocating such facilities may be so great that it renders development of a potential project uneconomical.

The development of potential hydroelectric sites may be prohibited by legislation. An example of such legislation is the Wild and Scenic Rivers Act, Public Law 90-542. This Act declares it is the policy of the United States that selected rivers of the nation which possess outstanding and remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values shall be preserved in free-flowing condition and, together with their immediate environments, shall be protected for the benefit of present and future generations. Within the Great Lakes Basin a segment of the Wolf River in Wisconsin has been designated as part of the national wild and scenic rivers system, and portions of the Maumee River in Indiana-Ohio and the Au Sable, Manistee, and Pere Marquette Rivers in Michigan have been proposed. This prohibits the Federal Power Commission from

licensing the construction of any hydroelectric projects on, or affecting, these designated segments of the rivers. Based on the foregoing considerations Table 10-8 lists, by river basin group, the undeveloped conventional hydroelectric projects in the Great Lakes Basin. A more detailed listing is given in Table 10-171. For purposes of this analysis, no conventional hydroelectric projects are considered likely to be developed in the Great Lakes Basin during the study period.

3.5 Pumped Storage Hydroelectric Power

A growing need to meet short-duration peak demands has caused an increased interest in pumped-storage projects. Although these pro-

TABLE 10-8 Summary of Undeveloped Conventional Hydroelectric Power

River Basin Group	Installed Capacity (kW)	Average Annual Generation (1,000 kWh)
1.0 Lake Superior		
Sturgeon River Basin	45,900	55,100
Ontonagon River Basin	15,000	83,000
St. Louis River Basin	10,000	57,000
Minor River Basins	67,400	354,600
TOTAL-Lake Superior	138,300	549,700
2.0 Lake Michigan		
Manistee River Basin	88,100	211,800
Grand River Basin	6,700	30,000
Kalamazoo River Basin	0	0
St. Joseph River Basin	7,200	29,400
Fox River Basin	5,000	12,400
Menominee River	40,900	175,800
Minor River Basins	31,200	113,100
TOTAL-Lake Michigan	179,100	572,500
3.0 Lake Huron		
Saginaw River Basin	0	0
Au Sable River Basin	47,500	128,500
St. Marys River Basin	0	0
Minor River Basins	0	0
TOTAL-Lake Huron	47,500	128,500
4.0 Lake Erie		
Cattaraugus Creek Basin	37,000	108,000
Huron River Basin	0	0
Minor River Basins	5,000	8,600
TOTAL-Lake Erie	42,000	116,600
5.0 Lake Ontario		
Black River Basin	110,845	494,000
Salmon River Basin	3,750	10,000
Oswego River Basin	11,900	41,700
Genesee River Basin	136,860	420,600
Oak Orchard Creek Basin	0	0
Niagara River Basin	0	0
Barge Canal Basin	0	0
St. Regis River Basin	77,300	198,000
Raquette River Basin	183,500	258,000
Grass River Basin	51,800	122,000
Oswegatchie River Basin	51,120	227,300
TOTAL-Lake Ontario	627,075	1,771,600
TOTAL Great Lakes Basin	1,033,975	3,138,900

jects are limited to cyclical operation, they offer the advantage of an emergency or short-term capability at a cost less than that of base load type plants.

The typical pumped-storage development consists of an upper and lower reservoir hydraulically interconnected through a generator pump system. Water from the lower reservoir is pumped into the upper or storage reservoir. It is held in the upper reservoir until system loads dictate the need for peaking capacity. When needed, the water from the upper reservoir is released and flows down to the lower reservoir through turbine-generator sets. At the end of the generating cycle, water retained in the lower reservoir is then pumped back into the upper reservoir where it is held until system requirements again call for peaking capacity.

Pumped-storage developments can be thought of as a storage battery, where electricity is held in the form of water potential until needed. Like any storage device there is a cost associated with its use. In the case of pumped storage, it is the cost of pumping the water to the upper reservoir. Allowing for the losses in the pumping and generation cycles, a typical pumped-storage development will require about one and a half kilowatt-hours of pumping energy for each kilowatt-hour of generation that it produces. Due to the cyclical nature of most electric utility loads, excess base load generating capacity is available during evening hours and over weekend periods. The upper reservoir is generally refilled during these periods.

In the Great Lakes Basin Power Region, there is presently one existing pumped-storage development, Lewiston, located in River Basin Group 5.1, and another, Ludington (Figure 10-10), under construction in River Basin Group 2.4. These two developments have a total capability of 2.1 million kW.

3.6 Projected Hydroelectric Power Supply

An appraisal of undeveloped conventional and pumped-storage hydroelectric sites which might be developed by 1990 was made by the FPC staff in updating the National Power Survey. In addition to the potential conventional hydroelectric sites given in Table 10-8, there are numerous potential pumped-storage hydroelectric sites within the Great Lakes Basin, particularly in the State of New York. The priority, timing, and amount of pumped-storage development depend upon the re-

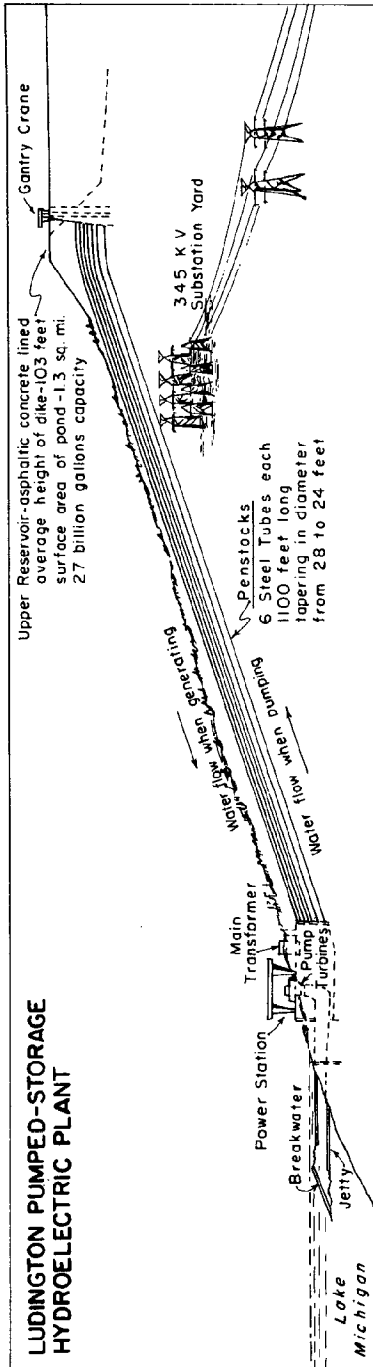
quirements and characteristics of the electric load, relative economics, and impact on the environment. Utilities in the State of New York are coordinated to a high degree through the New York Power Pool, and pumped storage as a source of peaking and reserve capacity figures prominently in expansion programs of the State's power supply.

The Northeast Regional Advisory Committee (NERAC) in its December 1968 Report to the Federal Power Commission lists 20 potential sites in New York totaling more than 14,000 MW. Four of these, totaling 3,500 MW, are in the Great Lakes Basin. Not included in the NERAC table is a 2,220 MW potential project on Lake Ontario (River Basin Group 5.2) listed by the Federal Power Commission staff in its draft of the chapter on pumped storage for the updated National Power Survey.

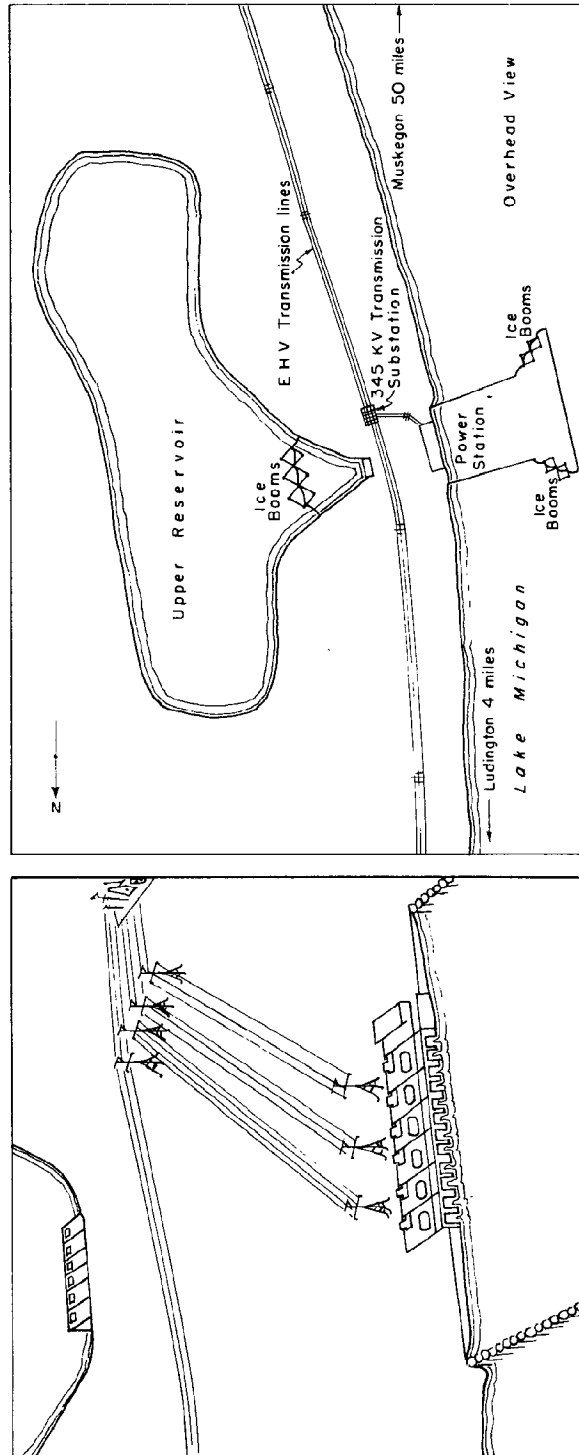
Pumped-storage potential in New York is substantial. The 240 MW Lewiston Plant at Niagara Falls of the Power Authority of the State of New York (POAS) is in existence, and POAS's 1,000 MW Blenheim-Gilboa project is under construction. POAS is also considering the development of another potential 1,000 MW site in the general area of Blenheim-Gilboa. In August 1970 the Federal Power Commission again issued a license to Consolidated Edison Company of New York, Inc. for its proposed 2,000 MW Cornwall project, also outside the Basin. However, environmental and other interests continue to oppose the development, and the matter is before the U.S. Court of Appeals for the Second Circuit. As of October 1971 no decision has been rendered.

Because of this, it has been assumed that 960 MW of pumped storage will be developed in River Basin Group 5.1 by 2000, and an additional 1,200 MW in the period after 2000. It is also assumed that River Basin Group 5.2 will have an installation of 2,100 MW by 2020.

The West Central and East Central Regional Advisory Committees, whose reports cover the remainder of the Great Lakes Basin, did not list any potential pumped storage sites within the Basin. However, the FPC staff estimates indicate that there are favorable sites for an installation of at least 1,400 MW in River Basin Group 1.1, and 800 MW in River Basin Group 1.2. These projects are not included in the projected power supply, because detailed engineering studies would be required to determine their economic feasibility. These studies would more carefully examine project construction costs and associated transmission costs, evaluate the energy losses in pumping and transmission, and compare



Cutaway view of pumped storage project shows how water flows through six steel penstocks between upper reservoir and Lake Michigan



Power station will house six units that will be capable of generating 1,872,000 kilowatts of electricity

FIGURE 10-10 Ludington Pumped-Storage Hydroelectric Plant. The 1,872,000 Kilowatt Ludington Pumped-Storage Hydroelectric Plant of the Consumers Power and Detroit Edison Companies, located on Lake Michigan, is the largest in the world. It began operating in 1973.

the results with the costs of alternative types of facilities. Environmental and aesthetic considerations would also be taken into account and might be determinative factors in the selection of particular projects for construction.

Although these and other projects actually may be constructed, this should not alter the results of the power study appreciably. The projected hydro capacity is used here only to

determine the thermal supply required and the corresponding cooling water requirements and consumption. Since the thermal supply is many times greater than the hydroelectric capacity which may be built, the amount of thermal capacity to be constructed should not be affected significantly. Similarly, the water data will not be affected materially. Table 10-9 lists the existing and projected hydroelectric supply by river basin group.

TABLE 10-9 Existing and Projected Hydroelectric Power Supply, 1970 through 2020

River Basin Group	Installed Capacity-MW				Generation-10 ⁶ kWh			
	Existing	Projected			Actual	Average Annual		
	1970	1980	2000	2020	1970	1980	2000	2020
Lake Superior								
1.1 West	88	88	88	88	451	429	429	429
1.2 East	42	42	42	42	174	174	174	174
Subtotal	130	130	130	130	625	603	603	603
Lake Michigan								
2.1 NW	150	150	150	150	712	712	712	712
2.2 SW-Wis.	-	-	-	-	-	-	-	-
2.2 SW-Ill.	-	-	-	-	-	-	-	-
2.2 SW-Ind. & Mich.	-	-	-	-	-	-	-	-
2.3 SE	36	36	36	36	125	138	138	138
2.4 NE-Lower Mich.	85	1,958	1,958	1,958	268	2,522	2,522	2,522
2.4 NE-Upper Mich.	2	2	2	2	5	5	5	5
Subtotal	273	2,146	2,146	2,146	1,110	3,377	3,377	3,377
Lake Huron								
3.1 N-Lower Mich.	50	50	50	50	183	175	175	175
3.1 N-Upper Mich.	60	60	60	60	419	431	431	431
3.2 Central	10	10	10	10	36	23	23	23
Subtotal	120	120	120	120	638	629	629	629
Lake Erie								
4.1 NW	^a	^a	^a	^a	-	-	-	-
4.2 SW	-	-	-	-	-	-	-	-
4.3 Central	-	-	-	-	-	-	-	-
4.4 East	-	-	-	-	2	2	2	2
Subtotal	-	-	-	-	2	2	2	2
Lake Ontario								
5.1 West	2,251	2,251	3,211	4,411	15,584	12,434	14,032	16,028
5.2 Central	86	86	86	2,186	298	266	266	3,763
5.3 East	1,207	1,207	1,207	1,207	8,017	7,852	7,852	7,852
Subtotal	3,544	3,544	4,504	7,804	23,899	20,552	22,150	27,643
Total GLB	4,067	5,940	6,900	10,200	26,274	25,163	26,761	32,254

^a Less than 1 MW

Section 4

PROJECTED ELECTRIC POWER REQUIREMENTS AND SUPPLY

Thermal-electric plants now make up approximately 88 percent of all the electric generating capacity in the Great Lakes Basin Power Region. That proportion is expected to increase to 90 percent by 1980. Predictions of the patterns of generation beyond 1980 are complicated by several factors. The electric power industry is one of the most dynamic in the United States, having experienced an annual growth rate of approximately seven percent for a number of years. The technology of electric power generation and supply is changing rapidly, resulting in larger and larger units which are made possible by the rapid load growth, the increasing reliance on EHV transmission, the construction of mine-mouth generation, the utilization of unit-type coal trains, and the large increase in the number of scheduled nuclear-fueled plants. New methods of generating power could make the conventional heat cycle obsolete by expelling the waste heat directly to the atmosphere or by using it in a combined steam cycle, thus eliminating or reducing the amount of waste heat to be dissipated by cooling water. These new methods include: MHD, or magnetohydrodynamics; EGD, or electrogasdynamics; thermionic generation; and the fuel cell. However, none of these should be in commercial operation before the turn of the century.

4.1 Projected Power Requirements

Projections of future power requirements through 1990 were completed by Regional Advisory Committees appointed to assist the Federal Power Commission in updating the National Power Survey. The Regional Advisory Committees, which are composed of representatives from all segments of the utility industry in their respective regions, relied on projections made by the major utilities operating in the region. These estimates were necessary to achieve full regional coverage, and the individual estimates and totals were rechecked with the industry utilities and were ultimately agreed upon. Also, reports are filed

annually by Regional Reliability Councils, in accordance with FPC Docket R-362, Order 383-2, Appendix A. These reports include power needs and installations for the ensuing ten years. Based on the reports of the Reliability Councils to 1980 and the estimates of the Regional Advisory Committees to 1990, projections through 2020 were completed by the FPC staff.

The annual energy requirements were projected to increase from 161 billion kWh in 1970 to 2193 billion kWh by 2020, an average annual compound growth rate of 5.4 percent for the fifty-year period. The associated annual peak load is projected to grow at an average annual compound rate of 5.3 percent from 28 million kW in 1970 to 365 million kW in 2020.

4.2 Projected Power Supply

The generating capacity required to supply the projected power requirements of each river basin group was also predicated by the reports of the FPC Regional Advisory Committees and Reliability Councils and extended by the FPC staff to the year 2020. The reserve capacity required and the energy produced in each river basin group were estimated with the assumption that the major utilities within a power region would completely coordinate their construction and operation programs after 1980.

Because cooling requirements of thermal-electric plants vary with different types of fuel, estimates were made of the amounts of energy to be produced by each type of thermal plant. The fossil fuel-nuclear capacity mix was developed to supply the increasing proportion of nuclear installations. Projections of the installed nuclear capacity in the Great Lakes Basin, relative to the total steam capacity, increased from approximately seven percent currently to 38 percent in 1980, 81 percent in 2000, and 98 percent in 2020. As nuclear plants become feasible in an area, there will be a transition period during which there will be a mixture of newly added nuclear and fossil

plants. After this period, except in special instances, all new base load plants will be nuclear, and the fossil plants will be phased out at the end of their useful life.

The nuclear power industry has recently been beset with problems which have caused some to believe that its growth will not be as rapid as previously supposed. The amount of orders for nuclear plants for the country rose from six million kilowatts in 1965 to 26 million kilowatts in 1967, but fell to 13 million kilowatts in 1968 and essentially to zero in 1969. However, in 1970 ten million kilowatts, 35 percent of the total steam capacity ordered, was nuclear. As of October 1970, 107 nuclear power plants with more than 82 million kilowatts were operating, under construction, or had at least purchased reactors.

Current problems besetting the nuclear industry will be overcome, and the long-term trend to nuclear plants will prevail. The actual proportion which will develop during each period will depend on the relative economics of nuclear and fossil plants, and an early solution to the problem of public acceptance of the new technology. The capacity mix which will be utilized is considered reasonable, and any change should not appreciably alter the estimated water requirements for cooling.

The projected hydroelectric capacity assumes that the existing plants, except for known retirements, will still be in service at the end of the study period. The energy production used for these plants in the projected periods is their average annual generation. The projected supply includes conventional and pumped-storage hydroelectric plants currently scheduled, and some which are tentatively considered to have development potential. Although more detailed studies may include additional projects, this should not seriously affect our results. The amount of hydro capacity projected is used only to determine the thermal supply required and the corresponding cooling water requirements and consumption. Table 10-9 in Section 4 lists the amount of hydro capacity projected in each river basin group.

A reasonable allowance has been made in the projected power supply for thermal generating capacity which does not require condensing water such as I.C. (internal combustion) units and gas turbines. These generally operate in the peak portion of the load at a low plant factor. New exotic types such as MHD (magnetohydrodynamics) may be developed and will probably be utilized in conjunction with conventional fossil or nuclear

steam plants as topping units. The main advantage of MHD would be the increased efficiency of the generating cycle, which is estimated to be approximately 15 percent better than that of the Rankine cycle in steam-electric generation. This would result in a proportional decrease in the amount of required steam generation. Because MHD does not require condensing cooling water, this would also result in a corresponding decrease in cooling water requirements. Although experimental and engineering investigations have been made in MHD technology, no complete steam unit-MHD cycle has yet been operated. Therefore, MHD is not expected to be operable by 1980. However, if MHD proves to be feasible, it would only affect the power and water data in the 2000-2020 period by a maximum of 15 percent.

The generating capacity includes plants now located and those expected to be sited on Lake Michigan in River Basin Group 2.2 in Illinois. These plants will serve the loads of that State located out of the hydrologic boundary of the Basin. Therefore, the loads of River Basin Group 2.2 in Illinois are not included in the load data. The power which will be exported from that area will be counterbalanced by firm imports of power projected in the eastern part of the Basin. Consequently, 5.7 percent of the power generated in the Basin is estimated to be exported in 1980, 7.7 percent in 2000, and 11.1 percent in 2020.

The majority of the thermal generating capacity to be installed in each river basin group will be installed near the shorelines of the Great Lakes because of the huge amounts of water required for the large thermal plants of the future. A detailed siting of the plants within the basins is not considered practical because of the complexities involved.

Tables 10-16 and 10-17 in the Addendum summarize the existing and projected power requirements and supply of the Basin. Similar data are given in the Addendum for each river basin group. The effects of hydroelectric and thermal plants on lake levels and flow regulations are included in Appendix 11, *Levels and Flows*.

4.3 Land Requirements

The large amount of additional power facilities needed to satisfy the increasing power demands of the Great Lakes Basin will require adequate land for plant sites and transmission lines right-of-way. The land re-

quirement for thermal plants varies from approximately 0.09 acres/MW to 0.17 acres/MW, depending on the size and type of plant. To install the projected steam-generating capacity in the Great Lakes by 2020, the amount of land required for thermal plants would be about 69,000 acres using the larger land requirement figure. Assuming the number of plant sites required is 150 to 200, and that they are all situated on the lakeshore, a maximum of approximately 200 miles of shoreline would be required out of approximately 4000 miles of existing mainland shores.

Right-of-way width for single circuit transmission lines is approximately 125 feet for 230-kV, 150 feet for 345-kV, 175 feet for 500-kV, and 200 feet for 765-kV. The corresponding acres per linear mile required, respectively, are 15, 18, 24 and 27. The total circuit miles of transmission lines planned for 1980 will require an additional 76,000 acres of land, and those contemplated for years between 1981-1990 will require another 34,000 acres.

The land requirements for power facilities must compete with those of other industries, housing, and public facilities. Power facilities must also overcome opposition from the public and communities which have become increasingly concerned with the appearance of their surroundings. In order to reduce opposition transmission lines should be routed so that they do not conflict with other land uses and public recreation and wilderness areas.

To assure adequate land for all the needs of the Basin, consideration should be given to more efficient land use through joint rights-of-way for several services, and through expansion and redevelopment of existing plant sites. Long-range planning programs are required to ascertain the feasibility of specific joint use functions and to obtain public sanction. Adequate public notice must also be given to allow inclusion of the utilities' plans with those of local planning and zoning programs.

Consideration should also be given to coordination of recreational opportunities with the siting of power plants. Coordination of recreational use and cooling facilities already exists in some areas. Several utilities outside the Basin are using their cooling ponds or lakes for such recreational activities as boating, picnicking, camping, fishing, and water-skiing. A private utility, in conjunction with TVA, is experimenting on how much increased production will result from catfish living in warm condenser discharges as compared to those living in unheated water. In addition, the exclusion areas, which comprise a considerable part of the land requirements for nuclear plants, can be used for hunting, fishing, and picnicking under existing Federal regulations, and some utilities are building visitor centers at nuclear plant sites and encouraging tourism.

Section 5

COOLING WATER REQUIREMENTS FOR STEAM-ELECTRIC GENERATION

5.1 Factors Determining Cooling Water Requirements

The principal demand imposed upon water supply by steam-electric generating plants is for condenser cooling purposes. Water introduced into the boiler is converted to steam to drive the turbogenerator unit. Steam leaving the turbine at less than atmospheric pressure is passed through the condenser where it is cooled and condensed back into water. The condensate is pumped back into the boiler in a closed circuit system. Thus, the only consumptive use in the boiler generator circuit is the feedwater make-up required to replace water losses. Losses in this circuit are quite small. The requirement for a 1000 MW plant operating at full load is estimated to be only 0.5 cubic feet per second. The major use at a steam-electric plant is the large separate flow through the condensers required to carry away the waste heat of condensation. Essentially, no water is used consumptively in the condensers, but losses do occur when condenser flows are returned to the source bodies of water at higher temperatures or passed through cooling towers or ponds.

Withdrawals of water for cooling at steam-electric plants currently constitute the largest nonagricultural diversion of water. Either fresh or saline water can be used for this purpose and, in some cases, sewage effluents are used. The amount of water required depends upon the type of plant, its efficiency, and the temperature rise within the condenser. The temperature rise of cooling water in the condenser is usually in the range of 10°F. to 20°F. Currently, a large nuclear steam-electric plant requires approximately 50 percent more condenser water for a given temperature rise than a fossil-fueled plant of equal size. After 1980, this added requirement is expected to decrease substantially. Such higher requirements result from the lower throttle steam temperatures and the resultant lower operating efficiencies of nuclear

plants. Firm planning for future generating capacity is not completed until four to seven years before such capacity becomes necessary. Accordingly, estimates of cooling water use in the years 2000 and 2020 can only be a rough guide which will be reviewed periodically as new situations develop. Projections of future water requirements for steam-electric plants have been made on this basis. However, there are alternatives to the demand for cooling water of good quality. For example, in the event that water is in short supply due to either scarcity or requirements of higher priority uses, the need for large quantities of flow-through cooling water can be almost entirely eliminated by the use of radiator-type closed circuit cooling towers. However, the costs are higher.

In addition to engineering considerations, power plant sitings must be responsive to the increased public concern for the quality of our environment. An electric power plant and associated transmission lines may affect fish and wildlife, aesthetics, and recreational values if poorly planned. On the other hand, the same plant in the right location, and properly designed as part of a comprehensive plan, will be an important asset to an area. A further discussion of this problem is in Section 6, Environmental Considerations.

Steam-electric plants, whether nuclear-fueled or fossil-fueled, operate on the thermodynamic process known as the Rankine cycle which limits the maximum theoretical thermal efficiency to approximately 60 percent. The best actual overall plant efficiency today is approximately 40 percent, including all thermal, mechanical, and electrical losses. This means that for each kilowatt-hour being produced by a plant with this efficiency, it is necessary to burn a fuel equivalent of 8530 Btu, or slightly less than one pound of average grade coal. Of this, 3413 Btu, the heat equivalent of one kilowatt-hour, is converted to electrical output and the remainder is lost. Plants having lower efficiencies require greater

gross Btu inputs to produce the same 3413 Btu per kWh of generation. Consequently, more waste heat is discharged to the condensers of these plants. It is apparent then that waste heat discharged to the condenser is inversely related to the efficiency of the plant.

All waste heat from steam-electric plants must eventually be discharged into the atmosphere. This can be accomplished in several ways. It may be transferred directly to the air or it may be transferred to water as an intermediate step and then to the air. Because of costs and engineering difficulties associated with the direct transfer process, nearly all the existing steam-electric plants in the United States use cooling water as an intermediate transfer agent.

The process of moving the waste heat from the steam-generation cycle to the water is accomplished by heat transfer through a steam condensing unit. In this process cooling water is passed through the condenser tubing. The expanded steam leaving the turbine is passed over the outside of the tubing and the waste heat remaining in the steam is transferred through the tubing to the cooling water which in turn carries it away.

5.2 Method of Determining Cooling Water Requirements

For a given rate of heat removal, the temperature rise in the cooling water is inversely proportional to the amount of water circulated through the condenser. The size of the condenser and the amount of water circulated can be varied substantially. The usual design is for a temperature rise through the condenser in the range of 10° to 20°F., with an average of approximately 15°F. For purposes of analysis, the method used in this report for determining cooling water requirement of a steam-electric generating station is illustrated by the sample calculation in Table 10-10.

For an average rise in cooling water temperature of 15°F. which is used throughout this study, the unit cooling water requirement is:

$$\frac{\text{ac-ft}}{\text{kWh}} = \frac{(0.001803^\circ\text{F})}{(15^\circ\text{F})} = (0.000120)$$

or 120 acre-feet for every million kilowatt-hours generated.

Nuclear plants (using current design standards) have a lower thermal efficiency than fossil plants, approximately 32 percent, or a heat rate of 10,750 Btu/kWh. Using this in the example above, and noting that there is no

significant heat loss directly to the atmosphere in nuclear plants, the unit cooling water requirement is 180 acre-feet per million kWh of electric generation. With continuing progress in design efficiencies it is expected that this requirement will decrease to approximately 105 acre-feet per million kWh by the year 2020.

5.3 Method of Determining Cooling Water Consumptive Use

The heat added to the water as it flows through the condenser may be dissipated to the atmosphere in several ways. In a flow-through system, the cooling water is returned to a body of either natural or artificial water, and the dissipation of heat is accomplished by evaporation, radiation, and conduction. If the heat is dissipated in a wet-type cooling tower, it is accomplished principally by the evaporation of water. In a dry-type cooling tower, the heat dissipation is almost entirely by conduction and convection. The water withdrawal requirement varies widely between these systems. The cooling water must be constantly replaced in the flow-through system, and partially replaced during each cycle in supplemental systems such as wet-type cooling towers or cooling ponds. There is virtually no replacement required in the dry-type cooling tower system.

5.3.1 Flow-Through Cooling

Where adequate supplies of water are available, and such use does not violate applicable water quality standards, the flow-through cooling system is usually adopted because it is the most economical method of cooling.

The primary consumptive use of cooling water is the amount of evaporation caused by the increase in water temperature as it passes through the plant's condensing unit. For purposes of this study it is estimated that, under average conditions, approximately 54 percent of the cooling in a surface discharge flow-through system is the result of this forced evaporation. However, this would be somewhat less for submerged type discharges because of resulting lower water surface temperatures. Based on a heat discharge of 4,900 Btu per kWh and 54 percent evaporation, approximately 2,645 Btu per kWh would be dissi-

TABLE 10-10 Sample Calculation—Cooling Water Requirement

<u>Operating Conditions:</u>	
Assumed over-all plant efficiency	36%
Assumed generator efficiency	97.5%
Heat equivalent of one kWh	3413 Btu
Fuel energy required (net plant heat rate)	9500 Btu/kWh
Heat loss from boiler furnace (10% stack loss) ²	950 Btu/kWh
Energy delivered to turbine from steam	8550 Btu/kWh
Generator output (3413 Btu + 7% plant use)	3650 Btu/kWh
Heat loss from generator ³	94 Btu/kWh
Energy removed in condenser (Energy delivered to turbine minus generator output)	4900 Btu/kWh

Cooling Water Required:

$$\begin{aligned}
 \text{Acre-ft/kWh} &= \frac{(\text{Energy removed in condenser})}{(\text{Heat Absorption Rate of Water})^4 \times (\text{temp. rise in cooling water})} \\
 &= \frac{(4900 \text{ Btu/kWh})}{(2,718,144 \text{ Btu/ac-ft/}^{\circ}\text{F temp. change}) \times (^{\circ}\text{F temp. change in cooling water})} \\
 &= \frac{(.001803^{\circ}\text{F})}{(^{\circ}\text{F temp. change in cooling water})^5}
 \end{aligned}$$

¹Cooling water required is the amount of water needed to pass through the condensing unit and is independent of the type of cooling.

²Negligible for nuclear plants.

³Generator cooling usually part of cooling water load and included in condenser load.

⁴1 Btu/lb. water/^oF temp. change in water; 2,718,144 lbs. of water = 1 ac-ft.

⁵Note that the quantity of cooling water required varies inversely with permitted temperature rise of cooling water.

pated by this process. Since the evaporation of one acre-foot of water consumes about 2,868 million Btu, the consumptive use is:

$$\frac{2645 \text{ Btu/kWh}}{2868 \text{ MBtu/ac.ft.}} = 0.9 \text{ acre-feet/million kWh.}$$

5.3.2 Cooling Ponds

Where natural bodies of water of adequate size are not available but otherwise suitable electric plant sites exist, cooling ponds may be constructed to provide the cooling water need. In this case, water would be recirculated between the condenser and the pond. Sufficient inflow into the pond would be needed to replace the evaporation induced by the addition of heat. It is estimated that in a cooling pond, evaporation provides 65 percent of the cooling. This increased evaporation rate is due to the higher water surface temperature in a cooling pond. Based on 4900 Btus to be dissipated, about 3200 Btus are lost through evaporation for each kilowatt-hour generated. This is equivalent to a loss of 1.1 ac. ft. per million kWh.

5.3.3 Wet Type Cooling Towers

Where suitable sites for ponds or reservoirs are not available and limited flows or water quality standards prevent use of available streams or other bodies of water, some other type cooling device must be used. In one device the cooling water is brought in direct contact with a flow of air and the heat is dissipated principally by evaporation. Such systems commonly use cooling towers with the flow of air provided by either mechanical means or natural draft.

In the wet cooling tower, the warm water may be sprayed into the air or allowed to flow onto a lattice network called fill whereby it is broken into droplets. This facilitates the evaporation heat transfer as air moves through the tower. The cooled water is collected in a basin under the fill from which it can be pumped back to the condenser to pick up more heat and again return to the cooling tower. In systems using wet-type cooling towers, evaporation accounts for about 85 percent of the cooling. There are some additional water losses because of spray drift and droplets entrained in the rising air stream. The amount of water required for drift is about 0.03 percent of the water circulated for a large power plant. The

total consumptive cooling tower loss averages about 1.5 acre-feet per million kWh generated based on the heat rate used in the sample calculation.

In addition to makeup water for evaporation and drift, water must also be diverted for blowdown. Blowdown is the periodic removal of solids which accumulate in the circulating cooling water. The circulating cooling water can be concentrated two to eight times before requiring blowdown, depending on the chemistry of the makeup water and the corrosion properties of the water system. The amount of blowdown water required varies from about 0.1 percent of the water circulated for a concentration of eight to 1.0 percent for a concentration of two. In other words, it can vary from 12 percent to almost 100 percent respectively.

The data included contain blowdown requirements based on a concentration of four. Individual case analysis is required to determine the actual number of allowable concentrations of circulating water which will prevent corrosion or scaling problems. The water used for blowdown generally is discharged back to the water source, in which case no water loss from the Basin will result.

5.3.4 Dry Type Cooling Towers

In a dry type cooling system the heat is dissipated to the air by conduction and convection rather than by evaporation. Thus, there are no evaporative losses of water with subsequent makeup requirements. No large dry cooling towers have been constructed in the United States and the largest one in the world, as of 1970, is used for cooling a 125 MW plant in England. Because of the large surface area required for heat transfer and the large volumes of air that must be circulated, dry cooling towers are substantially more expensive than evaporative towers. Overall efficiency in steam electric plants is decreased due to the large power requirement of dry cooling processes as compared to evaporative cooling processes. In addition, the technology of large scale dry cooling towers has not yet been proved.

5.3.5 Summary of Comparable Consumptive Uses by Various Cooling Systems

The relative consumptive use or cooling

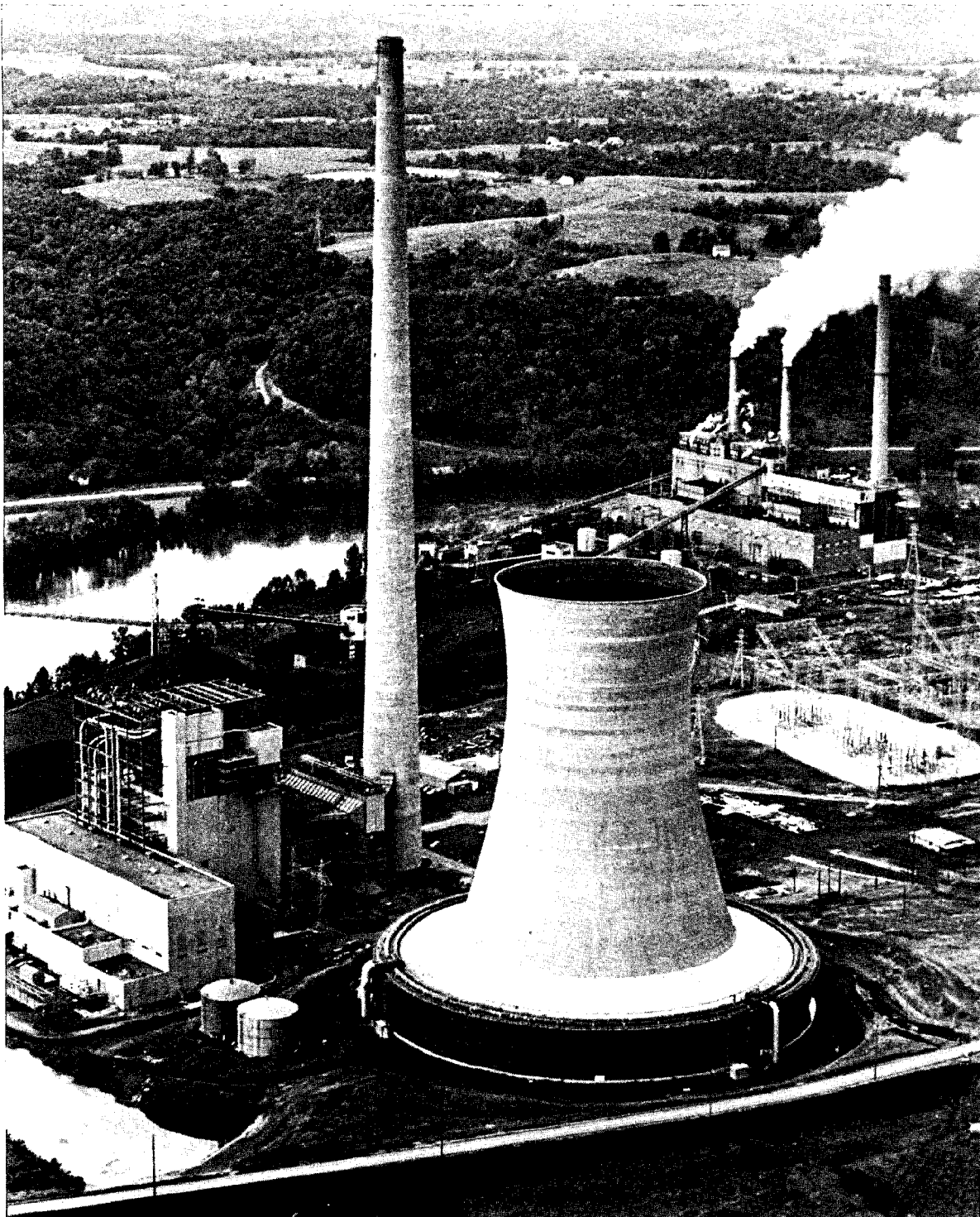


Photo courtesy of American Electric Power System

FIGURE 10-11 Natural Draft Wet Cooling Tower. The tower is 373 feet high and 395 feet in diameter and is used in conjunction with the 590,800 kW Muskingum River Plant of the American Electric Power System.

water losses, as stated in the preceding paragraphs, are summarized below:

Flow-through= 0.9 ac. ft./million kWh generated

Cooling pond= 1.1 ac. ft./million kWh generated

Cooling tower (wet)= 1.5 ac. ft./million kWh generated

5.4 Comparative Costs of Steam-Electric Cooling Systems

The costs of various types of cooling systems depend upon the design criteria and the site conditions. Ranges of costs are presented for the major types of cooling systems. The cost data were derived for an FPC staff study supporting the updated National Power Survey. They utilized such sources as utilities, Federal agencies, and cooling tower manufacturers. Because of the relatively limited number of nuclear plants for which data are available, the ranges of costs for such plants are largely estimated. The figures given apply only to plants originally designed for the specific type of cooling and should be interpreted as comparative rather than absolute values. Other qualifications noted in the table should also be taken into consideration.

For each type of system, costs of the condenser and auxiliaries have been excluded since they are common to all. The cost estimates for cooling ponds are predicated on the availability of sites with relatively low costs for land and relocation. Installation costs cover such items as pumps, piping, canals, ducts, intake and discharge structures, dams and dikes, reservoirs, cooling towers, and appurtenant equipment.

Construction costs for steam-electric generating plants which commenced operation in 1970 were about \$150/kW for fossil-fueled and \$200/kW for nuclear plants. The estimated costs for plants starting to operate in 1976-77 are \$200/kW and \$300/kW, respectively. The cost of the cooling system, including the condenser, can represent from 3.5 to 8 percent of the total, depending on the type of plant and cooling being considered.

In addition to differences in capital costs, there are operating expenses associated with each type of cooling. An operating expense common to all cooling systems is the cost of power needed to pump water through the system.

Cooling towers require water to be pumped

vertically 35 to 55 feet higher than flow-through systems. This added pumping power for towers is equivalent to about one-half percent or more of the plant output. Power to drive the fans in mechanical draft cooling towers is equivalent to more than one percent of the plant output. Annual operating and maintenance expenses, other than the cost of power for pumping and to drive fans, is equivalent to one percent or more of the investment costs of the cooling towers. Thus, considering the increased investment and operating costs, the use of evaporative wet cooling towers rather than flow-through systems may increase the cost of power by as much as five percent. Also, the higher water temperature at the condenser inlet that results from the use of cooling towers would produce a lower

TABLE 10-11 Comparative Costs of Cooling Water Systems for Steam-Electric Plants

Type of System	Investment Cost ¹ (\$/kW)	
	Fossil-Fueled ² Plant	Nuclear-Fueled ² Plant
Once through ³	2.00-3.00	3.00- 5.00
Cooling ponds ⁴	4.00-6.00	6.00- 9.00
Wet cooling towers:		
Mechanical draft	5.00-8.00	8.00-11.00
Natural draft	6.00-9.00	9.00-13.00

¹ These investment costs represent ranges derived as of the year 1969. Substantially higher costs per kilowatt may be encountered in specific situations.

² Based on unit sizes of 600 MW and larger.

³ Circulation from lake, stream, or sea and involving no investment in pond or reservoir.

⁴ Artificial impoundments designed to dissipate entire heat load to environment. Cost data are for ponds capable of handling 1,200 to 2,000 MW of generating capacity.

turbine efficiency and a loss of capacity. Thus, a capacity penalty needs to be charged against plants using wet cooling towers.

5.5 Cooling Water Availability in the Power Region

There are few streams in the Great Lakes Region with sufficient annual discharges to sustain the operation of a large steam-electric generating plant on a flow-through basis. Where such streams do exist, they have already been developed to near-capability. If future steam-electric generation is located on tributaries of the Great Lakes, it will require the use of such supplemental cooling techniques as cooling towers or cooling ponds. Another possibility is using the storage of older hydroelectric projects as sources of cooling water for thermal electric power generation. However, use of the Great Lakes as a water source will not result in a shortage of water available for steam-electric generation in the Region during the period of this study.

Cooling water demands for steam-electric cooling varies depending on a number of factors as indicated in the sample calculation. As a rule-of-thumb, a requirement of one cubic foot per second (cfs) per thousand kilowatts of installed capacity might be used. As a very rough check of streamflow adequacy for flow-through cooling at any given point, one might establish the requirement that the streamflow at that point must be three to four times the amount required for withdrawal. Applying the above rule-of-thumb to this requirement, we would therefore need a stream discharge of at least three cfs for each thousand kilowatts of installed capacity. Because some streams exhibit considerable seasonal variations in discharge, additional consideration must be given to the dependability of the flow during periods when the plant will be experiencing maximum demand. In general, tributaries to the Great Lakes cannot satisfy this requirement.

While there is no problem of water availability for plants located on the Great Lakes proper, there is a question of steam-electric plant compliance with water quality standards if flow-through cooling is used. As a result of the Federal Water Quality Act of 1965, the States have been called upon to prepare water quality standards for interstate waters within their boundaries. Several States within the Power Region have proposed water quality criteria relating to maximum permis-

sible water temperatures. These are subject to Federal approval. At the present time, the effect of existing and possible future regulations governing heat input into the Great Lakes is uncertain. Depending on the outcome of a number of ecological studies dealing with the effects of heat inputs from steam-electric generation and the direction of future regulations, supplemental cooling may become necessary for plants located on the Great Lakes. If properly accounted for in the planning stage, such a future requirement should not constitute a major barrier to power development in the Region. However, it will result in a higher consumptive use of cooling water and a higher operating cost to the utilities, and in all probability, a higher cost of electricity for the consumer.

5.6 Future Cooling Water Demands

In order to determine future cooling water requirements and consumptive water use in the Basin, projections of future steam-electric generation were made. These data are given by river basin group in the Addendum.

Case I is a breakdown of future generation based on the use of flow-through type cooling for future capacity additions except where supplemental cooling is required. On the other hand, Case II is based on all new capacity additions utilizing the wet tower form of supplemental cooling along with the gradual phasing out of existing flow-through type units. Actual future development will be somewhere between these two extremes. Nevertheless, subsequent discussion will relate these two cases to the limits of future water demands for steam-electric generation.

To show the effect that varying several of the more important parameters has on cooling water requirements and losses, four families of curves were plotted. The first two sets, Figures 10-12 and 10-13, illustrate the effect of discharge water temperature and varying heat rates on the amount of water required to pass through the condenser in both fossil-fueled and nuclear plants. Figures 10-14 and 10-15 show the relationship of plant heat rate to cooling water consumption (evaporation) for the various cooling methods. For purposes of this study a 15° F. temperature rise was selected as typical for all steam-electric generating plants throughout the study period.

As is evident from Figures 10-12, 10-13, 10-14, and 10-15, the efficiency of the generat-

TABLE 10-12 Great Lakes Basin Steam-Electric Generation by Type of Cooling

Year	CASE I ¹		Total
	Flow Through	Supplemental Cooling	
1965	96,798	1,179	97,977
1970	126,517	1,451	127,968
1980	263,161	8,533	281,694
2000	904,814	18,364	923,178
2020	2,343,859	15,283	2,359,142

Year	CASE II ²		Total
	Flow Through	Supplemental Cooling	
1965	96,798	1,179	97,977
1970	126,517	1,451	127,968
1980	141,317	140,377	281,694
2000	45,807	877,371	923,178
2020	-----	2,359,142	2,359,142

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

ing plant affects the amount of water required and lost. The efficiencies of fossil-fueled steam plants have been steadily increasing and have resulted in a decrease in the best U.S. plant heat rate from 10,600 Btu/kWh in 1947 to 8,690 Btu/kWh in 1968, and an average decrease from 15,600 Btu/kWh to 10,398 Btu/kWh in the same period. Improvement in unit efficiencies and the rate of decline in future net plant heat rates is not expected to be as great as in the past.

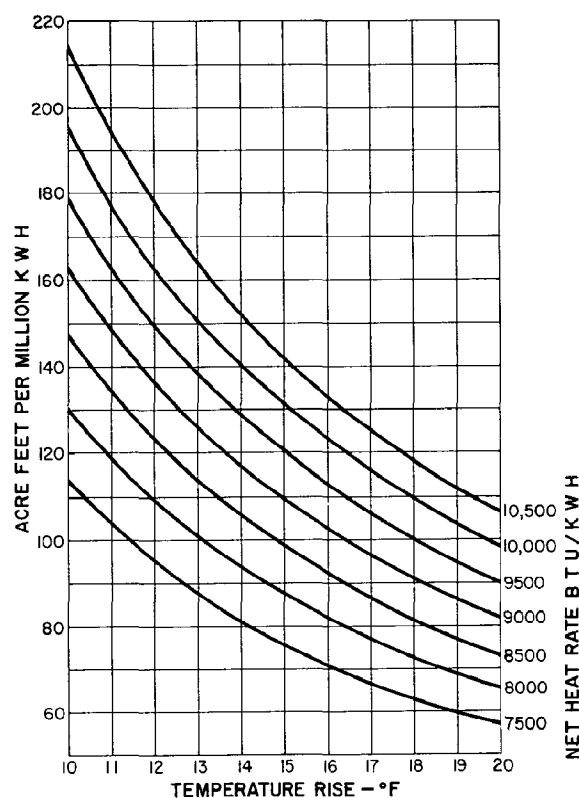
The efficiencies of the nuclear plants currently in service and planned for installation by 1980 are on the order of 33 percent, or 10,300 Btu/kWh. These are essentially the boiling and pressurized water types of nuclear plants. Advanced types of nuclear plants with increased efficiencies are being planned and built. Examples of this type are the high temperature gas-cooled reactor (HTGR) and breeder reactors which produce more fissile material than they consume. A prototype 40-MW HTGR was placed in commercial oper-

ation in 1967 (Peach Bottom No. 1) and a 330-MW HTGR (Fort Vrain No. 1) is under construction and scheduled for service in 1972. The design heat rate of the 40-MW plant is 9750 Btu/kWh and that of the 330-MW plant is 8790 Btu/kWh.

Based on the foregoing considerations, and the mix of new and older plants in service during each period, the following heat rates are assumed to be typical of the capacity that will be operating at each time period. In addition, new capacity was assumed to have a useful life of 30 years.

Type Plant	Net Plant Heat Rates (Btu per kilowatt-hour)		
	1980	2000	2020
Fossil-Fueled	9,000	8,700	8,500
Nuclear Fueled	10,300	9,000	8,000

The generation data of Table 10-20 in the Addendum were converted to estimated cooling water data based on the foregoing as-

**FIGURE 10-12 Cooling Water Requirements (Fossil Fuel Generating Plant)**

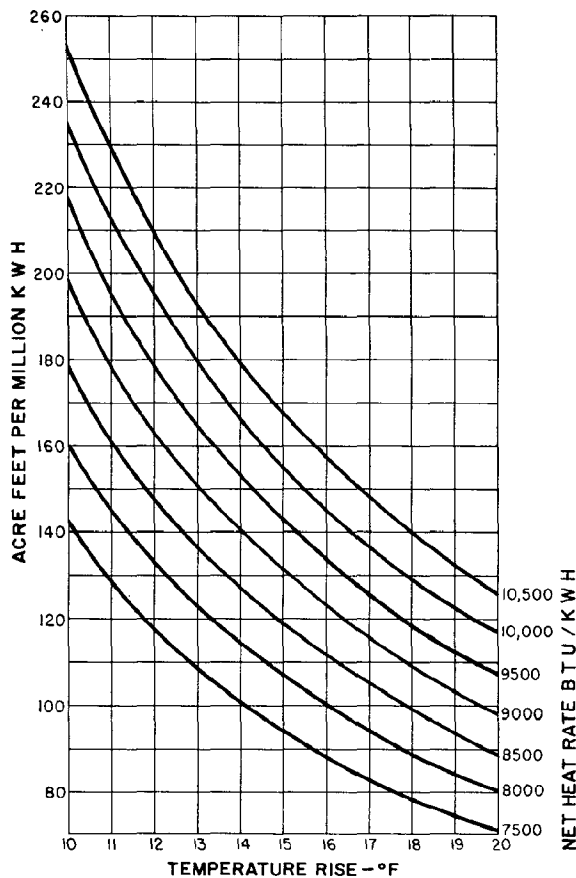


FIGURE 10-13 Cooling Water Requirements (Nuclear Generating Plant)

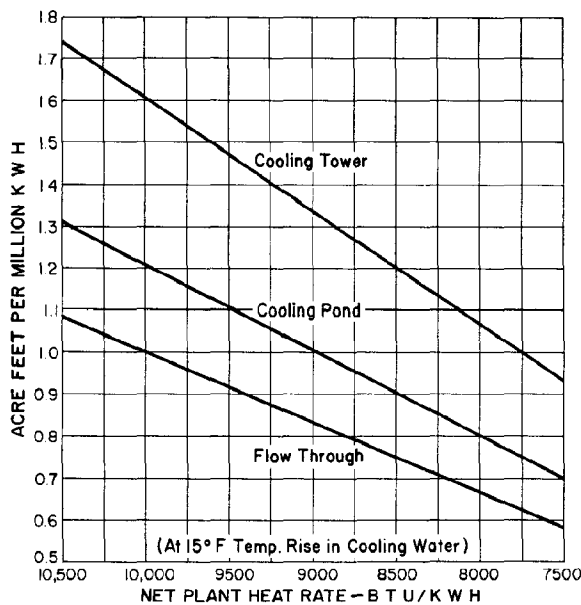


FIGURE 10-14 Consumptive Water Use (Fossil Fuel Generating Plant)

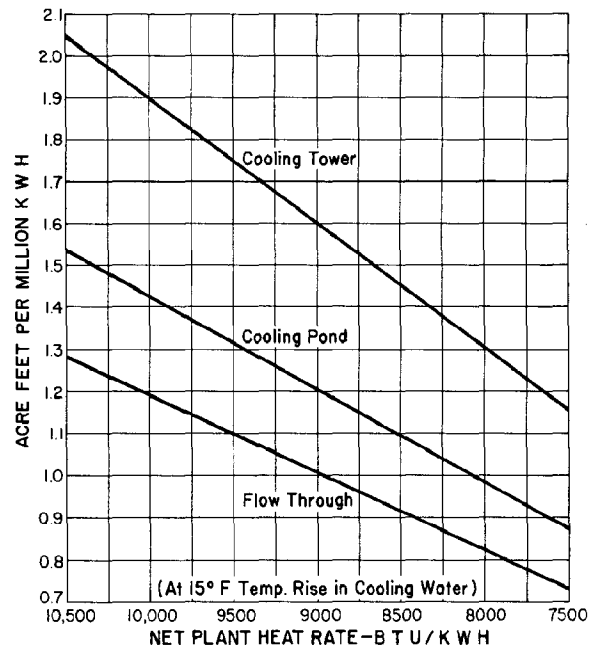


FIGURE 10-15 Consumptive Water Use (Nuclear Generating Plant)

assumptions and the method given in the sample calculation. Water data are given for the individual river basin groups in the Addendum and summarized for the total Basin in Table 10-14.

5.7 Interpretation of Determined Cooling Water Demands

Under the assumptions outlined in the previous section, the maximum limits for water demand resulting from steam-electric generation are produced by a combination of Cases I and II. These limits are given in Table 10-13.

In examining these maximum water demand limits the following general comments seem appropriate:

(1) The amount of cooling water to be circulated through a plant's condenser is not dependent on the cooling method used if the temperature differential across the condenser is kept constant with each type of cooling. However, optimum use of circulating water flows and cooling equipment to achieve the lowest cost may result in different water requirements for different types of cooling. In addition, water required is not a dependable measure of the adequacy of an area's water supply to meet steam-electric cooling needs because it includes the cumulative total of

water recirculated in cycling-type systems as well as reuse by downstream plants. Cooling water required is primarily a measure of the total volume of water that passes through condenser units.

(2) As given in Table 10-13, diversion is the maximum amount of water withdrawn to meet the needs of steam-electric generation as presented in Case I. Nearly 99 percent of this amount is available for possible reuse. In general, the amount of water required to be diverted compared to the amount of water available determines the type of cooling to be used. Although it requires the greatest diversion, flow-through cooling represents the most economical type of cooling. Given an adequate supply of water, Case I (flow-through) would be historically representative of the development pattern. Because of new economic considerations resulting from environmental constraints, the relative balance between cooling methods is changing. Longer and more costly intake and discharge facilities are required in new units utilizing flow-through type cooling.

(3) Consumptive use of cooling water is a further restrictive requirement on the location of steam-electric generation. Through the years, all large steam-electric plants in this country have relied on the use of water as a cooling medium. In areas with insufficient water to sustain flow-through type cooling

but adequate water to replace consumptive water use, some form of supplemental cooling has been used. Based only on the availability of water in the Great Lakes Basin, Case II (supplemental cooling) would not necessarily represent the future pattern of area power development. However, existing and proposed thermal discharge regulations are requiring more use of supplemental cooling systems.

(4) The future pattern of area power development will more likely be determined by the impact of new capacity additions on the ecology and environment than on the availability of water for cooling use. Because supplemental cooling methods operate essentially as closed systems, they have impact on the aquatic ecology of a specific area. Over the span of this study there will probably be a shift toward the pattern of development presented as Case II. The actual pattern will fall between the two extremes presented. Because projected water demands can be satisfied under either case, it will be possible to satisfy the actual demands that develop. The timely construction of new steam-electric generating capacity should not be restricted by the availability of an adequate water supply. It is impossible at this time to evaluate the overall ecological impact of new generation on the Basin. If, on the basis of a site-by-site analysis, cost and environmental considerations dictate the use of supplemental cooling, it is available.

TABLE 10-13 Maximum Water Demand Limits Resulting from Steam-Electric Generation

	1965	1970	1980	2000	2020
Cooling Water Required	13,036	19,545	38,083	119,017	251,338
Diversion ¹	12,867	19,308	35,239	116,669	249,734
Consumptive Use ²	102	184	379	1,402	3,032

¹Based on assumptions used in Case I (flow-through cooling)

²Based on assumptions used in Case II (supplemental cooling)

Section 6

ENVIRONMENTAL CONSIDERATIONS

During past decades the electric utility industry was primarily concerned with the construction of adequate facilities to provide economical and reliable power to its customers. In recent years system planners have had to consider the preservation of the natural environment.

The increasing population and expanding economy of this country require larger supplies of energy. Demands for electric energy double nearly every 10 years. The construction and operation of the facilities required to bring the needed power to consumers have an effect upon the water, air, and land resources of the natural environment. The impact of the power industry on the environment has been extensively explored in drafting the FPC updated National Power Survey. The following paragraphs represent some of the information contained in the Survey.

6.1 Thermal Water Pollution

Discharges of heated water from any source contribute to physical and biological changes in the receiving body. These changes can be beneficial, detrimental, or insignificant depending on the ecology of the particular water body and the desired uses of that body. When the discharge of heated cooling water produces effects that are detrimental to other desired uses of water, it is called thermal pollution. Thermal pollution is significantly different from other forms of pollution. It does not involve the addition of foreign matter to the environment, and therefore, does not directly contaminate the receiving waters.

The temperature of the cooling water used for condensing in a thermal power plant increases an average of 15° to 20°F. This will result in increased stream temperature at the point of discharge. Normally, the rise in stream temperature is dissipated rapidly. However, the large power plants of the future will discharge heat energy in extremely large quantities. The heat addition could affect the aquatic life of the water body receiving the

discharged heat, its waste assimilation capacity, and the suitability of the water for municipal, industrial, and recreational uses.

Thermal pollution problems can sometimes be eliminated or reduced by the correct engineering of water intake and discharge structures. Other times, use of supplemental cooling systems such as cooling towers or ponds may be required. These allow for the reduction in the temperature of the condenser cooling water before discharge of the cooling water into the receiving body of water, or before recirculation through the power plant. However, fogging and icing problems have been known to develop with use of towers. This may be objectionable from an aesthetic viewpoint as well as causing serious problems such as hazardous highways, etc.

6.1.1 Effects on Water

As the temperature of water is raised, the capacity of the water to hold oxygen is decreased. Thus, the amount of dissolved oxygen available under fully saturated conditions is less at elevated temperatures than at lower temperatures. For example, raising the water temperature from 55° to 68°F. results in a loss of approximately 13 percent in the oxygen carrying capacity of the water. However, only when the concentration of dissolved oxygen is greater than the resultant saturation level will heating alone drive off some of the oxygen. Observations at some existing power plants with once-through cooling indicate that, despite contrary findings from the laboratory, heating of water by the plants does not cause significant changes in the dissolved oxygen levels, although the saturation level may be changed.

The addition of heat to a water body can cause stratification because of the reduced density of the water at increased temperatures. The differences in density with a relatively few degrees differences in temperature are often sufficient to cause the waters to flow as separate and distinct layers. Thus, heated

water discharged to the surface of a water body tends to spread out and remain on the surface. Cooling water taken from the hypolimnion (bottom layer) of a reservoir and discharged after use at a temperature lower than that of the surface may move as an interflow between the surface and bottom layers.

6.1.2 Effects on Aquatic Life

Changes in temperature, chemical content, and flow rate of a water body may affect the species distribution and population of fish and other organisms indigenous to the water body. The thermal impact will not be the same on stationary organisms as on mobile ones.

The increasing need for heat dissipation in supplying the growing demands for electricity and the resulting demand for larger cooling water supplies for steam-electric plants have resulted in a number of studies on the effects of thermal discharge on aquatic life. However, predictions of the effects of both temperature changes and maximum temperatures are subject to considerable controversy. Additional field investigations under actual operating conditions are required to predict accurately the effects on natural biological communities.

Temperature changes normally play an important regulatory role in the physiology of fish and other cold-blooded aquatic animals. Reproductive cycles, digestive rates, respiration rates, and other processes occurring in aquatic animals are temperature-dependent. It is known that temperatures higher than those normally experienced can be detrimental to organisms in a variety of ways: survival of individuals can be impaired; organisms may be more susceptible to disease or to the effects of toxic agents; their food supply or their ability to catch food may diminish; and the inability to reproduce or to compete successfully with other organisms may eliminate a population. The elimination of one species in the food chain may change the ecological balance and cause significant changes in the species of plants and animals present.

However, experience has shown that in a number of locations the discharge of waste heat to a stream or reservoir has actually improved the available fishing in the vicinity of the discharge during the cooler months of the year. However, overfishing is a possible danger.

The use of water for cooling purposes at steam-electric plants may have other effects

on aquatic organisms than those resulting from thermal discharges. The adverse mechanical effects of passing fish, larvae, eggs, and other organisms through pumps, condensers, or plumes may indicate the need for screening intakes. Chemicals used for defouling the condensers may adversely affect fish and fish food organisms. However, it has been claimed by some utilities that to date there have been no adverse effects.

6.1.3 Effects on Water Uses

Although some uses of water bodies are not affected by changes in temperature, other uses may be affected either beneficially or adversely. Among the uses that may be affected by heat discharged with the cooling water from steam-electric plants are those for public water supplies and organic waste disposal. Some industrial uses may also be affected if water is required for cooling processes.

Chemical reactions tend to proceed at a faster rate as water temperatures rise. This could reduce the amount of chemicals required for the treatment of public water supplies. On the other hand, increases in summer water temperatures make drinking water less palatable and cause a greater percentage of blue-green algae. Some blue-green algae produce tastes and odors in water supply systems.

Temperature helps determine the organic waste assimilation capacity of a water body. The water temperature plays a triple role: it affects the rate of oxidation of pollutants, the capacity of the water to hold oxygen in solution, and the rate of reaeration of the water. Thus, the addition of heat to a stream may affect the assimilation of organic wastes.

6.1.4 Possible Beneficial Uses of Waste Heat

Studies are under way to find practical ways of utilizing waste heat from power plants. Although some progress has been made, it appears unlikely that uses for significant amounts of the available waste heat will be found in the near future. Some possible uses include space heating, industrial processing, improvements in irrigation agriculture, and advances in aquaculture. In winter, adding heat to a river could be beneficial if the added heat prevents an ice cover from forming. Reaeration could take place in the open water areas below thermal discharges. It has been suggested that instead of separate multi-

purpose retention reservoirs, it would be better to cooperatively plan recreational lagoons, lakes, and reservoirs that would combine recreation, wildlife, and other uses with that of cooling of thermal power plants. Recognition is also being given to the use of cooling ponds for recreational purposes.

Waste heat may be used in some instances to heat buildings. In some cases relatively low pressure or exhaust steam from thermal generating plants is used in industrial processes. However, on a national scale such uses of waste heat would account for a small proportion of the total available supply. Few industrial processes can utilize energy of such low quality.

Agriculture can potentially use waste heat. Heated water could be used for frost protection. Irrigation with heated water could promote faster seed germination and growth, and extend the growing season. Hothouses could be used to grow tropical or subtropical crops in the more temperate regions of the country. However, a number of problems need to be solved before large-scale use of heated water for irrigation could become common practice.

Another potential use of condenser discharge water is aquiculture. Marine and freshwater organisms may be cultured and grown in channels and ponds fed with heated water. For example, it may be possible to grow commercially valuable oysters in areas where they cannot normally reproduce or survive due to low water temperatures. Studies are being made of the possibility of increasing lobster production in Maine with the use of waste heat. Consideration is being given to the use of warm water in the Puget Sound region of Washington State to promote the spawning and growth of oysters, crabs, and mussels. Proposals have been made to use waste heat in Wisconsin to warm sport fish hatchery waters and increase growth rates.

The Long Island Lighting Company has an arrangement with a local oyster company which allows its Northport plant's cooling water discharge basin to be used for oyster production. Preliminary tests during the summer of 1967 showed that both oysters and hard-shelled clams not only survived but showed exceptional growth in the cooling water. The water, which passes through stainless steel cooling jackets, is not only nontoxic to the young shellfish, but it also supports a luxuriant growth of microscopic algae, possibly because it is drawn from a deep section of the bay and has a high nutrient content. Thus, young oysters can be grown in winter, and the

lagoon may prove to be a much more satisfactory environment for seed production throughout the year.

The warm waters of cooling ponds can provide important recreational areas. For example, lands adjacent to the 2,600-acre Lake Kincaid are being developed by the State of Illinois for recreational use. In addition to fishing, facilities are to be provided for boating, camping, and picnicking. This lake was created by the Commonwealth Edison Company to provide a source of cooling water for its 1,200-MW Kincaid generating station. The cooling pond for Virginia Electric and Power Company's 1,140-MW Mt. Storm plant is used for boating and water skiing. Kansas City Power & Light Company placed its Montrose Lake under the jurisdiction of the Missouri Conservation Commission which maintains facilities for various types of recreation.

6.2 Air Pollution

Another environmental consideration is air pollution resulting from the emission of particulate and gaseous matter (mainly sulfur dioxide and nitrogen oxides) into the atmosphere. Air pollution is one of the major environmental problems facing the nation. The urbanization and industrial expansion which have taken place in this country have followed a trend of concentrating people and their industrial and economic activities into relatively small urban areas. Most of these activities, including electric power generation, contribute to air pollution.

The effects of air pollution on human and animal health, agriculture, materials, visibility, and the climate are of concern to all levels of government, as well as to the public and industry. Of particular concern to the electric power industry are the possible effects on the atmosphere of power plant emissions.

6.2.1 Particulate Matter

Coal and, to a lesser extent, residual fuel oil contain incombustible materials that are converted to slag, dry bottom-ash, or fly ash. The two main variables affecting fly ash formation and emission are the ash content of the fuel and the manner of firing. Coal used in power plants normally contains from 5 to 20 percent ash. Most fuel oils contain less than two-tenths of a percent incombustible matter, while natural gas is essentially ash-free. Tur-

bulence of combustion carries some of the ash out of the furnaces in the form of fly ash.

Particulate matter, or fly ash, emitted from coal combustion consists primarily of silica, alumina, and iron oxide. Particulate matter emitted from fuel oil combustion consists of sulfates and cenospheres (partially burned droplets of oil). Emissions of particulate matter from natural gas combustion are caused primarily by dust particles in the gas. Other possible particulate emissions from power plants are smoke or soot resulting from the incomplete combustion of any fuel, but these are at a minimum in properly run, high efficiency installations.

The problem of particulate emissions from stacks of coal-fired electric plants can be largely solved by the installation of mechanical collectors and electrostatic precipitators. These devices remove from the emissions between 97 and 99 percent of the particulates. However, the costs increase considerably as the efficiency increases from 97 to 99 percent. A related problem is the disposition of the collected and precipitated materials. A current market does exist for some of the waste; fly ash can be used in concrete and road surfacing mixtures. Investigations are being made by utilities and other interested organizations to find other economical uses for this waste product.

6.2.2 Sulfur Oxides

Fossil fuels such as coal, oil, and gas all contain some sulfur in nature. During the combustion of coal, approximately 95 percent of the sulfur in the fuel is oxidized and enters the flue gas essentially as sulfur dioxide (SO_2) and a small amount of sulfur trioxide (SO_3). The relatively small overall sulfur oxide content of the flue gas, in the range of 0.2 percent to 0.4 percent of the total gas volume for plants using two percent to three percent sulfur coal, makes removal or recovery of sulfur dioxide gas from power plant exhaust systems difficult.

The residual fuel oil used in power plants also contains sulfur compounds. These can be extracted before sale, or low-sulfur fuel oil may be obtained by blending naturally occurring low-sulfur oils with the higher sulfur residual fuel oil. The residual fuel oil with a natural low-sulfur content sells at a premium for desulfurized residual oil, the amount depending on the various properties of the residual fuel oil, the degree of sulfur removal, and the quantity purchased.

Raw natural gas contains sulfur almost entirely in the form of hydrogen sulfide which can easily be removed in a purification plant before it is marketed. This prevents corrosion of pipelines and compressors. Consequently, the output of sulfur oxides due to combustion of natural gas used to fuel generating plants is negligible.

Sulfur can also be removed from coal before combustion. This can be done by mechanical or chemical methods of desulfurization at great expense. Conventional cleaning in a large capacity coal-preparation plant involves the separation of such waste products as shale, pyrite, or roof slate. Conventional mechanical coal cleaning methods are generally effective in removing up to 50 percent of the pyritic sulfur. This amount would not be adequate in meeting most proposed standards. Some pyrite removal may also be attained in the process of grinding and cleaning coal at the power plant. Chemical removal methods are still in the research and development stage, and considerable work must be done before the process will become available.

Recently, studies have been made relating to the conversion of coal to synthetic gas which can be burned without emission of sulfur oxides. However, the delivered cost of synthetic gas is high in most areas of the country. It will not be used extensively as a source of primary energy for electric power generation in the next decade.

In addition to fuel desulfurization, attention is currently being given to flue gas cleaning processes. Of the several processes that have been proposed to remove sulfur oxides from stack gases, injections of limestone or dolomite into the boiler furnace or into a flue gas scrubbing solution may offer the simplest and least expensive method of control. The limestone process does not require heavy investment in equipment and can be adapted to any size installation or added to existing power plants, providing the space for retrofitting is available. Although research is being done to develop a method of sulfur recovery based on this process, this method does not yield a recoverable product. With no sulfur recovery, the economics of the process is not dependent on the market availability of sulfur compounds, and the utility need not be burdened with the marketing of chemicals.

The limestone process can be accomplished by the injection of pulverized limestone into the combustion chamber to react with SO_2 . This method may remove 30 to 50 percent of the SO_2 depending on the quality and quantity of limestone added and the operating condi-

tions. A limiting factor at existing plants is the capacity of existing dust collection equipment. To achieve the goal of SO₂ removal efficiencies of 50 to 60 percent, it may be necessary to add more than twice the theoretical amount of limestone. This would more than double the dust loading of dust collectors. This is considered a dry process in that no scrubbing device is used to collect the fly ash.

The wet scrubbing limestone process may remove up to 90 percent or more of the sulfur oxides. The wet process uses an aqueous limestone slurry scrubbing solution which can remove particulate matter as well as oxides of sulfur. Limestone can also be added to the furnace as in the dry process. The wet scrubbing process has advantages over the dry process such as a higher efficiency for sulfur oxide removal, less boiler operation interference, and generally lower operating costs for large power plants. The wet process has the disadvantage of requiring a reheat of the exhaust gases after scrubbing in order to achieve proper plume rise. An additional problem may be the water pollution potential of the scrubbing solution which some believe may be as serious as the SO₂ problem. The wet process appears to be better suited to larger power plants such as base load plants. The dry process releases gas at higher temperatures, requires less capital investment, and is simpler to operate. Both processes increase the solid waste disposal problems.

Another process being investigated is the Monsanto catalytic oxidation process. In this process, hot flue gases first pass through a high temperature, high efficiency electrostatic precipitator to remove fly ash. The clean gas then passes through a catalytic bed of vanadium pentoxide where the sulfur dioxide is oxidized to sulfur trioxide. The flue gases are cooled sufficiently to condense and to collect a sulfuric acid mist. The by-product is a moderately concentrated sulfuric acid. One problem of this process is that a high flue gas temperature is necessary for the oxidation reaction. Furthermore, fly ash tends to foul the costly catalyst. High temperature precipitation is expensive, and costly corrosion resistant materials are needed through much of the exhaust system.

The Kioyoura-Tokyo Institute of Technology Process is similar to the Monsanto catalytic oxidation process. After the gases pass through the catalytic reactor, ammonia gas is injected, resulting in the formation of 99 percent pure ammonium sulfate crystals that can be used for fertilizer. However, there is a very

limited market for ammonium sulfate in this country. Kioyoura has reported that the ammonium sulfate process can be adapted to manufacture ammonium phosphate which is the fertilizer currently in increased demand in the U.S.

Wellman-Lord, Inc. has developed a sulfur dioxide removal process somewhat similar to the catalytic oxidation process in that flue gases are first cleaned by an electrostatic precipitator. The cleaned gas is then passed through a non-catalytic reactor which is continuously washed by a reactive solution of potassium sulphite which absorbs SO₂, SO₃, and particulates. The reacted solution can be taken to a stripper to recover high quality SO₂ gas to be used for production of elemental sulfur or sulfuric acid.

The Chemical Construction Company (Chemico) is in the process of developing an alkaline scrubbing process for SO₂ removal from flue gases. By using magnesium oxide directly in a venturi-type scrubber, Chemico plans to remove fly ash and SO₂. The resulting magnesium sulfite will be separated from the fly ash, dried, and heated to evolve sulfur dioxide and to regenerate magnesium oxide for recycling. The SO₂ will be converted to sulfuric acid or reduced to elemental sulfur. Chemico predicts good removal of SO₂, and removal of essentially all particulates.

Because of the high cost of absorbent regeneration, Chemico has proposed the idea of a central recovery plant which would receive sulfite salts from several power plants and other industrial sources and return the regenerated absorbents to these sources.

Two processes for sulfur removal from stacks based on solid absorbent methods are the Reinluft process and the Alkalized Alumina process. In each case, a solid absorbent is used to collect SO₂. The Reinluft process regenerates activated char to release SO₂ which is then utilized in the manufacture of high-grade sulfuric acid. The tendency of the char to ignite, in addition to the complexity of operation, makes the process unpromising for the present, and it has been withdrawn from the market. An advantage of the Alkalized Alumina process is that elemental sulfur could be manufactured from the hydrogen sulfide extracted during regeneration of the absorbent. Elemental sulfur is easier to store or ship than acid. However, there are several drawbacks to the process. It is extremely involved, highly complicated, and nearly as complex as the operation of the power plant. Furthermore, the alumina process requires

too much additional space for many of the existing power plants with limited land availability.

Other approaches are currently being investigated which may offer new departures in the future. Some of these processes are:

- (1) a combination of ammonia scrubbing and ammonium phosphate production (TVA)
- (2) scrubbing with molten salts at high temperature, the molten carbonate process (Atomics International)
- (3) use of gaseous ammonia with regeneration of the ammonia gas for reuse. The process would also remove some nitrogen oxides (Bureau of Mines).
- (4) use of phosphate rock as an absorbent after sulfur dioxide oxidation to attempt to produce a fertilizer product directly in the gas stream (Battelle)
- (5) iron oxide (alpha form) as an absorbent (Siemens)
- (6) hydrogen sulfide injection into the flue gas stream and catalytic reaction with sulfur dioxide *in situ* to form sulfur (Princeton Research and Peter Spence)
- (7) carbon monoxide injection into the flue gas stream, followed by catalytic reaction with sulfur dioxide to form sulfur (Chevron Chemicals)
- (8) absorption by sodium hydroxide solution followed by regeneration by electrolysis (Ionics—Stone and Webster)
- (9) absorption by potassium polyphosphate (TVA)
- (10) oxidation by nitrogen oxides (Tyco)
- (11) use of zinc oxide as absorbent (Aerojet General)
- (12) absorption by manganese dioxide followed by dry regeneration (Japan)
- (13) absorption by barium carbonate slurry and reduction to sulfur (TVA)
- (14) use of metal oxide as absorbent followed by reduction in place (Shell, Esso)
- (15) SO₂ absorption process using cooled absorbent in a high mass transfer efficiency controlled vortex gas scrubber (CVX) (Tailor & Co.)
- (16) use of potassium formate which is regenerated after recovery of elemental sulfur (Consolidation Coal Company)

The process costs of the various methods for sulfur removal from flue gases are uncertain. While numerous approaches are being investigated, there are as yet no available processes on a commercially reliable basis, and it is only recently that some large demonstration units were put into service. Experience from large

prototype full-scale utility installation is needed to obtain more meaningful answers. Preliminary cost estimates, as published by their advocates, are summarized in Table 10-14. Since the technology is changing rapidly, the cost figures should not be taken as absolute but rather as comparative values.

6.2.3 Other Pollutants

Other pollutants, such as aldehydes, polynuclear hydrocarbons, carbon monoxide and gaseous hydrocarbons are a very small proportion of the total emissions from power plants because of the highly efficient combustion achieved. The major pollutants from the power industry, in addition to particulates and sulfur oxides, are nitrogen oxides. Nitrogen oxides removal systems are in the early stages of research and development. Present sulfur oxides removal systems are not considered effective for removal of nitrogen oxides. Nitrogen oxides (NO_x) from coal combustion represent about one-fourth the pollutants formed by sulfur oxides (SO_x).

Nitrogen oxides, under the influence of sunlight, undergo a chemical reaction to form photochemical smog and ozone which are highly irritating to the eyes and damaging to vegetation. In fog, nitrogen dioxide may combine with water to form nitric acid which can cause corrosive damage to plants and materials and irritate the lungs.

Nitrogen oxides emitted from power plants are caused by the high furnace temperature and nitrogen content of the air in the combustion zone. Other factors affecting nitrogen oxides formation are fuel type, manner of firing, and amount of excess air. It is difficult to achieve control of NO_x in power plants because of the interacting effects of other pollutants. If attempts are made to reduce nitrogen oxides by reducing the amount of excess air, an increase in the amounts of carbon monoxide, particulates and hydrocarbon compounds may result.

Controls for the NO_x produced by coal-fired systems have not been studied extensively on a commercial scale. Tall stacks for better dispersion of flue gases may help to reduce ground level concentrations of NO_x as well as other pollutants. This may be a practical interim solution until other methods are perfected. More research is required to develop technology that will effectively resolve the problem.

TABLE 10-14 Estimated Costs of Sulfur Dioxide Removal Processes

Process	Sulfur in Coal	Capital Cost (\$/kW)		Operating Cost (\$ per ton of coal)				Products Providing Credit
		500 MW	1000 MW	No By-Product Credit		With By-Product Credit		
				500 MW	1000 MW	500 MW	1000 MW	
Alkalized Alumina	3.0%	25.30	24.41	3.28	3.12	2.21	2.05	Sulfur @ \$35/ton
Catalytic Oxidation (Monsanto)	3.0%	-----	25.00	----	1.75	----	----	Sulfuric acid at \$13.50/ton
Limestone - Dry (TVA)	3.5%	6.32	3.95	0.98	0.86	----	----	None
Limestone - Wet (TVA)	3.5%	10.85	8.21	1.11	0.64-0.90	----	----	None
Limestone - Wet (Combustion Engineering)	3.0%	-----	2.22	----	0.45	----	----	None
Wellman-Lord, Inc.	3.0%	11.40	8.20	1.09	0.88	0.02	0.01	SO ₂ @ \$15.60/ton
Chemico	3.0%	5.00-7.00	5.00-7.00	0.75-1.00	0.75-1.00	not available	not available	Sulfuric acid or Sulfur

Note: The price of sulfur fluctuates widely. The price has ranged from \$24.00 per long ton in 1962 to \$42.00 in 1968. Sulfuric acid prices may vary from \$5.00 to \$20.00 per ton. The uncertainty of sulfur --sulfuric acid markets makes estimation of product credits difficult.

6.3 Environmental Aspects of Nuclear Power Plants

The potential injurious effects of nuclear power plants to man and his environment have recently gained prominence and threaten to delay or forestall the progress of the industry. Acceptance of nuclear power by the public will depend largely on increased knowledge of the principles and safeguards involved. This will allay their fears concerning the safety of the plants. To many, an atomic power plant is synonymous with an atomic explosion. However, there is no atomic explosion in the generation of electricity. Essentially, the nuclear reactor in a power plant is a heat source used to generate steam, and replaces the furnace in a fossil plant. The remainder of the generating facilities are the same in both. The nuclear power plant is fueled with low-enriched fuel, whereas the bomb uses highly enriched materials. All experts agree that under no circumstances can the nuclear power plant explode. The main concerns of the knowledgeable public are:

(1) In case of a catastrophic accident, even though no explosion occurs, what about the release of radiation?

(2) Are the standards governing the controlled radioactive releases adequate?

(3) Are the radioactive wastes handled safely?

(4) Will the cooling water discharged from nuclear power plants overheat the receiving water bodies?

6.3.1 Catastrophic Accident

The most likely causes of catastrophic accidents are from human error, or an electro-mechanical malfunction. To prevent these accidents, the plant is designed to withstand an earthquake. It also has special safeguards against human or electromechanical failures. Safety control rods automatically shut down the plant if any abnormality occurs. This prevents the meltdown of the reactor fuel core, which is the only effect of a malfunction—not an explosion. Also, duplicate coolant systems are provided to further assure against reactor meltdown from failure of the coolant system. In addition, if the remote possibility of a meltdown did occur, an air-tight containment building surrounds the entire system to prevent any released radioactivity from escaping into the atmosphere. Some critics are not satisfied and warn that there is no absolute guarantee that the containment structure could hold a major meltdown, despite the built-

in safeguards and assurances of AEC to the contrary.

6.3.2 Controlled Radioactive Releases

More controversy is centered around the controlled radioactive releases from nuclear power plants than the unlikely contingency of a meltdown. Small quantities of radioactive gaseous and liquid wastes are routinely released from nuclear plants. The gaseous waste is released to the atmosphere through a stack, and the liquid waste is diluted and released to the water body supplying the plant. The remaining solid waste is collected and transported to offsite burial grounds.

The controlled waste releases must not exceed limits set by Federal safety standards. All radioactive wastes are monitored and analyzed prior to release for conformity with the standards. In addition, constant surveillance is maintained in and around the nuclear plant to make sure no radiation limit is exceeded. Actual experience with operating nuclear plants has shown that, generally, radioactive materials released are quite minor, and any radiation exposure to an individual from a power plant is less than the person receives from normal background radiation. Radiation is, and always has been, part of man's natural environment. Natural radiation emanates from cosmic rays entering the earth's atmosphere, from radioactive materials in the earth and air, and, surprisingly, from within man's own body tissues. Hence, exposure to radiation is not a new phenomenon.

Despite the low level of permissible and actual radiation releases, some people believe that if the general population received the amount permitted, the releases would constitute a health hazard. It is also claimed that even if total emissions may not be harmful today, the multiple nuclear plants to be constructed by the year 2000 will result in an accumulative effect because of the ability of radioactive materials to concentrate in aquatic life and in agricultural plants. These claims are vigorously denied by the Atomic Energy Commission which states that those factors were taken into consideration when the radiation standards were set, and continual monitoring of plants, animals, and aquatic life will alert AEC to any unusual concentrations.

Hence, the entire question of nuclear power plants presenting a radiation hazard is limited to finding acceptable waste release limits to use as standards. There are methods being

developed that would practically eliminate the need to discharge gaseous and liquid wastes, and thus would have negligible radioactive releases. If successfully implemented, these methods would reduce the possibility of hazardous radioactive releases from normal operation of nuclear power plants.

To illustrate the extent of radiation produced by an actual operating nuclear power plant, let us take the Niagara Mohawk's Nine Mile Point plant on Lake Ontario near Oswego, New York, which began operating late in 1969. The New York State Environmental Conservation Department has stated that monitoring in the vicinity of the plant has shown no measurable increase in radioactivity since generation began. Samples of air, Lake Ontario algae, fish and water, and milk and farm products from nearby farms were tested regularly. Any radiation from the power plant was indistinguishable from natural background radiation.

6.3.3 Handling of Radioactive Wastes

The possibility of an accident causing release of the solid radioactive wastes being transported from a power plant to a reprocessing plant, and the burial of the wastes after reprocessing are other areas of concern. The wastes are shipped by truck or rail in 70-ton tanks specially designed to withstand severe impact and high temperatures. The possibility of radioactive material escaping from its containment during an accident is unlikely, but if it did, the radiation effect should be minimal because of the small amount of waste shipped at any one time.

The usable portion of the waste is extracted at the reprocessing plant. The gaseous waste after reprocessing is released through a stack to the atmosphere. The remaining waste is required to be solidified after a period of time and then moved to a permanent burial ground. Deep salt mines are considered the best for this purpose. Several sites have been considered, and the one near Lyons, Kansas, appears to best satisfy the requirements. However, use of this site, as well as any site which might be chosen as a repository for radioactive wastes, has been opposed. Community enlightenment and establishment of acceptable guidelines are required if selection of burial sites is to become acceptable to the public.

The gaseous wastes released from reprocessing plants contain radioactive isotopes

which, in small quantities, are not harmful and cannot concentrate to a great degree. However, the large quantity of these isotopes which will be released from reprocessing plants to satisfy the future fuel demands may result in a large buildup by the turn of the century. Techniques are being studied and developed for containing these isotopes at the reprocessing plants. Because there is an interval of time before these emissions present an actual problem, intensive research and development should solve the problem. A pilot program is being conducted which may remove more than 99 percent of one of the isotopes from the emissions of a reprocessing plant.

6.3.4 Heated Water Discharges

The heated discharges of water used for cooling in nuclear power plants also cause concern. Because the plants are less efficient than fossil-fueled power plants, more heat is discharged into the supplying water body. However, the nuclear plants of the future should be as efficient as the modern fossil-fueled plant. In any event, if heated water discharges are a problem, supplemental cooling systems such as cooling towers can be used to remedy the situation where warranted.

6.3.5 Conclusions

The shift to nuclear power plants is desirable from the view of conservation of our natural resources. At the present rate of increased use of coal in industrial and power plants, it is estimated that the recoverable supply of coal in the nation would be exhausted in 100 years. Proved recoverable reserves of natural gas are being reduced, and at the current rate of production, they will last only 15 years. However, increased exploration will probably extend this considerably. Oil resources are also dwindling. Thus, by increasing the use of nuclear fuel for electric power production, fossil fuels will be freed for other vital uses.

However, the supply of nuclear fuel is not without limit. The development of a commercial fast breeder reactor is required by the late 1980s in order to produce enough cheap nuclear fuel to supply the requirements of the nuclear power industry. A crash program for development of the fast breeder has been advocated.

In addition to conservation of natural resources, another advantage of nuclear power plants is that they are much cleaner than fossil-fueled plants. The air pollution problem of fossil plants is considered by some to be more of a potential health hazard than the controlled radiation releases from nuclear plants. Nuclear power plants do not emit significant quantities of air pollutants. Although reactors employed in nuclear power plants produce radioactive materials, most of these are incorporated in solid waste products and are not factors in air pollution. These solid waste materials are subject to several levels of control, collection, and treatment. A small amount of low-level radioactive gases is released into the atmosphere under carefully controlled conditions. The radiation level and quantity of releases are measured and limited to regulated amounts. The release limits used are based on radioisotope concentration guides which have been established by international and national radiological authorities.

If a person somehow were exposed to a large amount of radiation produced by a nuclear power plant, "sudden death" would not automatically result. It has been estimated that the annual radiation exposure which could be fatal for an individual would have to be almost 1000 times the permissible release limit used as an exposure standard in 1970, and almost 100,000 times the design basis for nuclear power plants. The annual exposure required to produce even nausea or discomfort in an individual is 200 times the permissible 1970 release limit and 20,000 times the design basis.

6.4 Aesthetics

In addition to concern about the impact of power facilities on the quality of air and water, increasing concern has been expressed by various groups at the Federal, State and local levels about their effect on the appearance of the cities and countryside and the protection of natural, historic, scenic, and recreational values. The problem of aesthetics of power facilities falls into three general categories—distribution, transmission, and generation.

6.4.1 Distribution Facilities

There are many overhead distribution lines in existence with multiple crossarms, numerous conductors, and conspicuous appurtenances which may be deemed unattractive. To

overcome objection to the construction of these lines, manufacturers and utilities have developed many new designs, materials, and concepts which have improved the appearance of overhead facilities. Some of these are:

- (1) keeping the number of conductors on one pole line to a minimum
- (2) eliminating crossarms
- (3) replacing wood poles with concrete or steel poles
- (4) making hardware components and supports from fiberglass and in more attractive shapes
- (5) using colors which blend more compatibly with the sky and surroundings in the construction of substations, insulators, transformers, poles, and other distribution equipment
- (6) careful routing of distribution lines, making greater use of natural screening to soften harsh silhouettes and improve the appearance of the surroundings

Another solution is to put distribution lines and facilities underground. Underground systems have been confined to high load density areas such as the downtown sections of large cities. Underground systems require designs and equipment with an extremely high degree of reliability and capability for growth without major changes. The costs of these systems are comparatively high. Lower cost underground distribution systems have recently evolved which are being used in residential and other low load density areas. Many new residential subdivisions, apartment developments, and shopping centers are now employing underground systems.

Conversion of existing overhead systems to underground systems is very costly. It has been estimated that the cost of converting all existing overhead distribution to underground would be \$150 billion. This compares with the present total investment in distribution facilities of approximately \$40 billion. Thus, the conversion of all existing facilities does not appear practical, but it may be done on a selective basis.

6.4.2 Transmission Facilities

Transmission systems differ from distribution systems because they generally transport large blocks of power greater distances and at higher voltages. The problem of protection of the natural, historic, scenic, and recreation values in the design and location of transmission right-of-way and facilities is of major con-

cern. To solve this problem, guidelines have been recommended which include:

- (1) the selection and clearing of right-of-way routes
- (2) the location of transmission towers and overhead lines
- (3) the design of transmission towers
- (4) the maintenance of transmission line right-of-way
- (5) possible secondary uses of right-of-way
- (6) the location of appurtenant above-ground facilities

Compliance with these recommended guidelines would minimize the impact of transmission facilities on environmental values.

New designs for transmission towers such as tapered poles can improve their appearance. Choice of colors and materials can also aid their appearance. Joint use of rights-of-way should be emphasized in future planning and acquisition programs to minimize land use conflicts.

Underground high voltage electric transmission lines for long distances are not technologically or economically feasible at the present time. There are currently approximately 2,000 miles of underground lines of 69-kV and higher, but these represent less than one percent of the total high voltage transmission system. They are generally located in densely populated areas where overhead right-of-way is not available or is prohibitively expensive. They are also of comparatively short lengths. There are major technical problems in the construction of underground transmission lines and facilities, and the cost is many times that of overhead. It has been estimated that in suburban areas, underground lines cost 8½ times the cost of overhead lines at 138-kV and 15 times at 345-kV. Consequently, it is not expected that many transmission facilities will be installed underground in the next decade or so.

6.4.3 Generation Facilities

Hydroelectric plants can be improved in appearance by blending the structures with the natural features of the site. The architects, designers, contractors, and landscape planners should work together to achieve a unified design and compatibility with the surrounding landscape. Current licenses for hydroelectric projects being issued by the Federal Power Commission contain specific provisions requiring the applicant to preserve and en-

hance aesthetic values in the plans for project works.

Steam-electric plant site selections involve the consideration of many factors. The need to improve the appearance of power facilities to reduce the adverse impact upon the environment is now generally recognized as one of the factors to be considered. The aesthetic nature of power plants, both fossil-fueled and nuclear, can be improved by good architectural design and landscaping treatment. Nuclear plants have an aesthetic advantage over fossil-fueled plants by not requiring large fuel storage areas, ash disposal areas, and tall stacks.

In the construction of cooling systems associated with power plants one must also consider aesthetics. A flow-through system involves the least noticeable change in the natural environment. The required structures are generally located at the edge of a stream or reservoir, with a major part of the installation being placed underground or underwater.

Cooling ponds are similar in structural requirements to flow-through systems and may provide recreational opportunities. However, both ponds and flow-through systems may have adverse aesthetic effects because warmwater discharges may promote the growth of algae and also induce fogging.

Wet, natural-draft cooling towers involve large structures which are usually considered unsightly. Many are 400 feet or more in height, making it difficult to blend them into the natural environment. The large quantities of moisture given off can cause fogging in warm weather and icing in winter. Mechanical draft towers are not as tall as natural draft structures and can therefore be more easily obscured. However, they release moist air at lower elevations which creates greater fogging and icing problems. Dry type towers would eliminate the fogging and icing problems, but because they are comparatively larger in volume than the wet type, it would be more difficult to blend them into the surroundings. The large volumes of warm, dry air released could possibly affect local weather conditions.

6.5 Federal Legislation Affecting Power Plant Siting

The environmental and ecological problems accompanying the siting of power plants has increased the concern of environmentalists, conservationists, the public, Federal and

local agencies, and the electric utilities. Congress officially recognized the water pollution problem by enacting the Federal Water Pollution Control Act in 1956. This Act was amended in 1961, 1965, 1966, 1970, and 1972 with shifts in administration of the Act from the Public Health Service to the Department of Health, Education, and Welfare and to the Department of the Interior. The objective of the original Act, as amended in 1961, was the enhancement of the quality and the value of the nation's water resources and the establishment of a national policy for the prevention, control, and abatement of water pollution. The 1965 amendment (Water Quality Act) allowed the States to establish water quality standards for interstate streams and coastal waters, subject to approval by the Secretary of the Interior and the Environmental Protection Agency. The 1966 amendment (Clean Water Restoration Act) authorized Federal financial assistance for research and development of water pollution control measures, and for the construction of waste treatment works.

On January 1, 1970, the National Environmental Policy Act of 1969 (Public Law 91-190) was enacted. The purposes of the Act are: "To declare a national policy which will encourage productive and enjoyable harmony between man and his environment; to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man; to enrich the understanding of the ecological systems and natural resources important to the Nation; and to establish a Council on Environmental Quality."

Another act, Public Law 91-224, was passed by Congress on April 13, 1970. Under Sec. 21(b)(1) of Title I (the Water Quality Improvement Act of 1970) of PL 91-224, any applicant for a Federal license or permit to conduct any activity which may result in any discharge into navigable waters shall provide the licensing or permitting agency a certification from the State, or from the interstate water pollution control agency having jurisdiction. State certification will assure that such activity will be conducted in a manner which will not violate applicable water quality standards. No license or permit shall be granted until the required certification has been obtained (unless it has been waived), or if certification has been denied.

Title II of Public Law 91-224 is known as the "Environmental Quality Improvement Act of 1970." The purposes of this Act are:

- (1) To assure that each Federal department and agency conducting or supporting public works activities which affect the environment shall implement the policies established under existing law; and
- (2) to authorize an Office of Environmental Quality, which, notwithstanding any other provision of law, shall provide the professional and administrative staff for the Council on Environmental Quality established by Public Law 91-190.

In addition to water pollution legislation affecting construction of power plants, the Atomic Energy Act of 1954, as amended, requires licensing of all nuclear plants. This Act gives the Atomic Energy Commission (AEC) the authority to license and regulate nuclear plants with respect to protection of public health and safety from radioactive discharges.

More recently, the President's Reorganization Plan No. 3 of 1970 was announced on July 9, 1970 consolidating the major pollution responsibilities of the Federal government. This removed the Federal Water Quality Administration (FWQA) from the Department of Interior and the National Air Pollution Control Administration (NAPCA) from the Department of Health, Education, and Welfare and incorporated them into a new agency, the Environmental Protection Agency (EPA), effective December 2, 1970. Also transferred to EPA is the function of the Atomic Energy Commission pertaining to the establishing of environmental standards for the protection of the environment from radioactive material.

Following the formation of EPA, Executive Order 11574, Administration of Refuse Act Permit Program, was issued on December 23, 1970. The purpose of the Order is to control and reduce pollution of the nation's waterways by establishing a new, coordinated program of water quality enforcement under the Refuse Act of 1899. All persons and firms proposing to commence or to continue the discharging or depositing of any material into the navigable waters of the United States or their tributaries must obtain a permit. Any person or firm failing to apply for or not receiving a permit will be liable to criminal or injunctive proceedings.

Prior to the formation of EPA, the NAPCA was the principal Federal agency concerned with administering programs concerned with air quality. In 1955, Congress authorized the Department of Health, Education, and Welfare (HEW) to conduct research into the effects of pollutants. The Clean Air Act of 1963 authorized a broad program of Federal research, technical assistance, and other aids to

State and local air pollution control programs. It also contained specific mandates for HEW to conduct research on sulfur oxides, to develop criteria on air pollution agents, and to conduct abatement proceedings.

The Air Quality Act of 1967 amended the Clean Air Act and provided an intergovernmental program for the prevention and control of air pollution on a regional basis. HEW was required to designate air quality control regions and issue quality criteria and reports on control techniques. State governments were then to establish ambient air quality standards for the air quality control regions and to adopt plans for implementation of the standards and submit them to HEW for review and approval. NAPCA has delineated a number of air quality control regions and has also issued criteria and control documents for sulfur oxides, particulates, carbon monoxide, hydrocarbons, oxidants, and nitrogen oxides. This was to be followed by States adopting air quality standards and implementation plans under provisions of the 1967 Act.

The more recent Clean Air Act amendments of 1970 (PL 91-604), approved December 31, 1970, greatly strengthened the Federal air pollution control authority. Following enactment, the Administrator of the newly formed EPA was directed to issue national primary and secondary ambient air quality standards. Primary standards were defined as standards required to protect the public health. Secondary standards were defined as standards to protect public welfare from any known or anticipated adverse effects. EPA has proposed standards for sulfur oxides, nitrogen oxides, and particulates. After adoption of the standards, the States are required to submit implementation plans to the Administrator within nine months. In the case of primary standards, these plans are to be carried out within three years, unless an extension is granted. Special attention is given in the Act to new stationary sources such as new power plants. This requires that the Administrator list categories of stationary sources and propose regulations establishing Federal standards of performance for new sources which reflect the degree of emission limitation achievable through the application of the best system of emission reduction which has been adequately demonstrated. Each State must then develop procedures for implementing and enforcing the standards. If these standards are adequate, the EPA Administrator delegates authority to the State to implement and enforce the standards.

Because of the aforementioned water and air pollution acts, the Federal Power Commission, on October 22, 1970, adopted a new rule requiring electric utilities to annually submit FPC Form 67, containing air and water quality control data which will provide a basis for the development of effective environmental quality control programs. The Federal Power Commission also issued Order No. 415 on December 4, 1970, implementing the National Environmental Policy Act which requires licensees to supply detailed information relating to environmental factors.

In addition to water and air pollution legislation which affects siting of electric power plants, other Federal acts have been passed relating to the protection of fish and wildlife, the preservation of wild, scenic, recreational, and historic areas and the preservation of aesthetic values. Compliance with these statutes is required of hydroelectric licensees by the Federal Power Commission.

The previously mentioned Federal acts have resulted in corresponding actions by the State and local governments. Many have established air quality criteria for sulfur oxides and are exploring criteria for nitrogen oxides and carbon monoxides. All States have submitted water quality standards for their interstate and coastal waters for approval by the Office of Water Quality of the EPA.

In addition, there were a number of bills pending before Congress during its 1971 session concerning power plant siting. It seems to be the general consensus that some sort of legislation on this matter will be passed but its terms cannot be defined at this time.

6.6 State and Local Authority Affecting Power Plant Siting

In order to ascertain the degree of control that State and local governments exercise over the siting of power plants and routing of transmission lines, in early 1970 the Federal Power Commission surveyed the utilities in each FPC power region. The following is a summary of the survey for each State in the Great Lakes Basin. In some cases where known changes have occurred since early 1970, these are included in the summary. However, the increased attention to environmental matters by the States has caused numerous recent changes in their internal structure which may not be included. Additional information on the subject can be found in Appendix F20, *Federal Laws, Policies, and*

Institutional Arrangements, and Appendix S20, State Laws, Policies, and Institutional Arrangements.

6.6.1 Illinois

Prior to the construction of a new thermal electric power plant certification by the Illinois Commerce Commission under Section 55 of the Illinois Public Utilities Act is required showing that the public convenience and necessity require such construction. A similar certificate is required before construction of a new transmission line.

A certificate is required in the above cases whether or not the right of eminent domain is to be exercised. Prior to exercising the right of eminent domain, Illinois public utilities must receive a separate order from the Illinois Commerce Commission pursuant to Section 50 of the Public Utilities Act.

In 1970 the General Assembly passed the Environmental Protection Act to control, prevent, and abate pollution of the surface and underground waters in the State and to enhance the quality of the environment in other aspects as well. The Illinois Environmental Protection Agency (IEPA) is designated as the pollution control agency of the State under the Act, and a Pollution Control Board was established to determine whether pollution exists. The IEPA presents technical information as evidence before the Board. The IEPA has broad powers for controlling pollution of the State's waters through rules adopted by the Board. Permits must be obtained from the Agency before persons may construct, install, or operate any equipment, facility, vessel, or aircraft, or before increasing the quantity or strength of any discharge of contaminants. Other permits may also be required.

The Act makes it illegal to discharge into the environment any contaminant that causes or tends to cause pollution or violates standards. The Board may seek cease and desist orders for violations of the Act or Board Rules and Regulations, specifying the conditions and time for accomplishment. It may also impose monetary penalties or revoke permits.

The regional organizations in the Illinois area which exercise responsibility in environmental matters include the Four-State Enforcement Conference on Lake Michigan Pollution (Illinois, Indiana, Wisconsin, and Michigan), the Chicago Metropolitan Air Quality Region (six northern Illinois counties and two northern Indiana counties), and the

St. Louis Metropolitan Air Quality Region (counties from Illinois and adjacent counties from Missouri).

The Four-State Enforcement Conference on Lake Michigan Pollution was called together by the Federal government at the request of the State of Illinois. It is a continuing body. Specific authority rests with each State, but final authority can be exercised by the Federal government.

The Metropolitan Air Quality Region groups are essentially ad hoc and act only in an advisory capacity. Action on a decision is handled by the individual State air quality control boards, their technical staff, and advisors, but there is no binding agreement between States that assures mutual decisions will be acted upon.

The Metropolitan Sanitary District requires a permit for any discharge of industrial wastes into the waterways of Cook County, Illinois, which can cause pollution. It also requires a permit for all construction within or directly adjacent to the Sanitary and Ship Canal, the Calumet-Sag Canal, portions of the North Branch of the Chicago River, and the North Shore Channel.

Permits are also required for the construction of stacks and for process and stack emissions. In several instances local governments have applicable ordinances, but State requirements still prevail as the minimum standards.

6.6.2 Indiana

Only the Public Service Commission of Indiana can grant a new utility the right to construct a thermal electric power plant. This is done by obtaining a Certificate of Public Convenience and Necessity.

With regard to existing utilities, no specific Certificate of Convenience and Necessity is required to build a thermal electric power plant. However, the Commission is required to approve construction plans and expenditures by an existing utility if the existing utility can show that the public interest will be served by that construction and expenditure.

Prior to the use of the waters of the State of Indiana for cooling purposes in generating stations, authority must be obtained from the Indiana State Board of Health through the Stream Pollution Control Board. Information on the effect of construction within a floodway and removal of water and material from a stream must be submitted to the Indiana De-

partment of Natural Resources in order to obtain approval. In addition, approval of the Federal Aviation Agency must be obtained for the height of smoke stacks on generating stations. Local zoning regulations may also apply.

No specific certification is required from the Public Service Commission of Indiana for the purposes of obtaining the right of eminent domain except in cases involving a second utility coming into the territory of an existing utility. The right of eminent domain is granted to existing utilities by statute, and the exercise of the right is determined by the courts of Indiana.

In the past the Public Service Commission of Indiana has made no attempt to exercise its authority with respect to environmental review and it has no specialized staff for such purposes. However, such factors are within the statutory powers of the Commission, and its present staff could be utilized to discharge this responsibility. The Department of Natural Resources is fully staffed to discharge its responsibilities on matters of thermal effects on water of the State. The Air Pollution Board of the State Board of Health is fully staffed to treat matters of air pollution.

Regional organizations have been formalized for environmental matters: the Ohio River Valley Sanitation Commission; the Great Lakes Commission; the Wabash Valley Interstate Commission; and the Ohio Valley Interstate Commission. These bodies are continuing bodies constituted under specific multi-State compacts.

6.6.3 Michigan

Before constructing a thermal electric power plant, an electric utility must obtain an air use approval from the Air Pollution Control Commission and a permit from the Department of Natural Resources for any dredging or filling in the bottomland of any navigable lake or stream. Before operating such a plant, an electric utility must obtain an operating permit from the Air Pollution Control Commission and an Order of Determination from the Water Resources Commission. Full information as to the nature of the effluent involved must be furnished to the respective Commission. The Order of Determination of the Water Resources Commission must include such "restrictions as in the judgment of the Commission may be necessary to guard adequately" against "discharge

into the waters of the State any substance which is or may become injurious to the public health, safety or welfare; or which is or may become injurious to domestic, commercial, industrial, agricultural, recreational or other uses which are being or may be made of such waters; or which is or may become injurious to the value or utility of riparian lands; or which is or may become injurious to livestock, wild animals, birds, fish, aquatic life or plants or the growth or propagation thereof be prevented or injuriously affected; or whereby the value of fish and game is or may be destroyed or impaired." The Water Resources Commission has promulgated water quality standards which have been approved by the Federal Secretary of the Interior. These cover everything except temperature standards. Public hearings on new temperature standards were held by the Commission in 1970 and in 1971. Revised standards have been adopted and have been transmitted to EPA for approval.

The Water Resources Commission Order must also approve of any construction or filling within the flood plain, stream bed, or channel of any stream.

The Department of Natural Resources is responsible for the protection and development of the State's natural resources. In this capacity, it reviews plant development plans for their adequacy, particularly with respect to fish, wildlife, and recreation resources. The Department of Natural Resources cooperates with the Bureau of Sport Fisheries and Wildlife and provides comments and recommendations on the preservation and protection of fish and wildlife resources appropriate under the Fish and Wildlife Coordination Act.

The Air Pollution Control Commission permit "continues in effect as long as the installation performs in accordance with the conditions upon which the permit is based."

Local air pollution approvals or permits are required by some local ordinances. Local ordinances may sometimes be more restrictive than the State statute.

Other State approvals and permits include approval by the Department of Aeronautics on lighting of certain tall structures, approval by the Department of Public Health as to the sanitary sewage system, a Boiler Permit from the Department of Labor and a Railway and Highway Crossing Permit from the Public Service Commission. No State agency has jurisdiction over plant siting, but applicable environmental regulations and standards must be met.

An electric utility must obtain a certificate of convenience and necessity from the Michigan Public Service Commission before constructing an electric transmission line only if it is to be constructed in the territory of another electric utility. However, such construction is subject to local zoning ordinances under Michigan law.

The Michigan Department of Public Health radioactivity standards are essentially the same as those of the Atomic Energy Commission.

6.6.4 Minnesota

There is no specific certification required from a single Minnesota agency before an electric utility can construct a thermal power plant. However, several State and local agencies have degrees of control over plant siting. Permits are required from the Department of Natural Resources to utilize surface and ground waters, and from the State Pollution Control Agency to discharge wastes, build industrial facilities in accordance with planning and zoning regulations, build tall structures, and accomplish aspects of a similar nature. As for transmission lines, there is no single Minnesota agency which can grant certification. Several State and local governmental entities must be approached to obtain the required land-use and building permits, and permits to cross public lands and waters.

In 1967 the Minnesota Legislature created the Pollution Control Agency to deal directly with problems relating to water and air pollution. The Pollution Control Agency was the successor of the Water Pollution Control Commission, and all duties and powers formerly vested in that commission were transferred to the new agency. These included the administration and enforcement of all laws relating to water pollution, the investigation and gathering of data required for administration and enforcement of the pollution laws, establishment of water pollution standards, and the issuance, continuance, or denial of permits for discharge of wastes.

In addition to the Great Lakes Basin Commission, there are two other river basin commissions that have major functions in Minnesota. One is the Minnesota-Wisconsin Boundary Area Commission, a State organization similar to that of Wisconsin. The other is the Souris, Red, Rainy River Basin Commission, a Federal-State organization. Both of these organizations were constituted under

specific State legislative authority, but their functions are advisory rather than regulatory.

A regional authority in the Minneapolis-St. Paul metropolitan area was established under State legislative authority. It is known as the Metropolitan Council and has coordinating and advisory functions.

Many counties in Minnesota have comprehensive planning and zoning boards, established under authority of the State Legislature. These boards have regulatory authority over thermal plants and transmission lines.

Under the terms of a Flood Plain Management Act passed by the Minnesota Legislature, the Minnesota Commissioner of Conservation establishes standards for flood-plain zoning to be implemented by counties. These standards affect thermal plants and transmission lines.

6.6.5 New York

Under the Public Service Law no utility under the jurisdiction of the Public Service Commission may begin construction of an electric plant in territory where it has not previously been authorized without first having obtained the permission and approval of the Commission (P.S.C. Law, Art. 68).

Under the Siting Bill (Laws of 1970—Chapter 272), no person shall, after July 1, 1970, commence the preparation of a site for the construction of a major utility transmission facility in New York State without having first obtained a Certificate of Environmental Compatibility and Public Need issued with respect to such facility by the Public Service Commission.

A "major utility transmission facility" is defined as an electric transmission line of 125 kV or more, extending one mile or more, or 100-kV to 125-kV extending more than ten miles (except for underground lines in cities of 125,000 population); and a gas transmission line of more than 125 psi extending 1000 feet or more.

The Condemnation Law as amended by Chapter 272 of the Laws of 1970 states that it is no longer necessary to show the necessity of the acquisition of property for public use if the property is to be used for construction of a major transmission facility, to which a Certificate has been issued by the Public Service Commission.

Certain functions of the Department of Health, the former Water Resources Commis-

sion, and the former Department of Conservation have become part of a new Department of Environmental Conservation. The handling of air and water pollution controls and the setting of water quality designations, and protections against encroachment of State waters are among the functions of the new Department.

Under recently enacted legislation the Governor has the power to appoint a Council of Environmental Advisors to advise the Governor with respect to environmental matters. A State Environmental Board has been established to coordinate the interests of various State agencies. Local environmental councils function in an advisory capacity to local municipalities to review all projects which will affect the environment.

The State of New York has given its Atomic and Space Development Authority significant control over nuclear generating sites. A law enacted in May 1968 authorizes the authority to designate plant sites and then acquire, develop, prepare, and furnish them by sale or lease to electric utilities.

The State Public Service Commission does not require a utility to obtain a certificate before constructing steam-electric power plants within the utilities' own existing franchised areas, but such certification is necessary for construction of plants outside such areas.

In 1970 the legislature passed and the Governor signed bills effecting a reorganization of the Public Service Commission and the delegation of additional powers to the Chairman. Another measure proposed by the Governor would establish, within the Commission, a vehicle to resolve in one proceeding, without undue delay, questions growing out of the location of major utility generating stations. The legislation was not passed in the 1971 session.

6.6.6 Ohio

The Ohio Constitution authorizes laws adopted to encourage forestry and to conserve the natural resources of the State. The State Public Utilities Commission does not require the issuance of certificates for the construction of either steam electric power plants or transmission lines. Nevertheless, the Ohio Water Pollution Control Board has the power to issue, revoke, modify, or deny permits for the discharge of sewage, industrial waste, or other wastes into Ohio waters after considering the technical feasibility and economic

reasonableness of removing the polluting properties from such wastes.

In 1951, Ohio adopted the Water Pollution Control Act of Ohio. This Act directs the Ohio Water Pollution Control Board to:

- (1) conduct water pollution research and study
- (2) develop programs to prevent, control, and abate water pollution
- (3) issue, modify, or revoke orders prohibiting discharge into Ohio waters, requiring construction of new disposal systems, and prohibiting additional connections or extensions of a sewerage system when the same would result in additional pollution discharge into State waters
- (4) issue, revoke, modify, or deny permits for discharge of sewage as aforesaid
- (5) establish water quality standards
- (6) investigate alleged acts of polluting activities

In the absence of a permit the Act proscribes all water pollution discharge as a public nuisance.

In 1967 Ohio adopted the Air Pollution Control Act. The Act provides that the Ohio Air Pollution Control Board may:

- (1) conduct research and studies relevant to the air pollution control
- (2) develop programs to prevent, control, and abate air pollution
- (3) recommend ambient air quality standards for various areas of the State
- (4) recommend air contaminant emission standards to achieve established air quality standards
- (5) require emission reports to be filed with the Board
- (6) establish air pollution monitoring stations within the State
- (7) require the submission of plans and specifications for proposed installations that may cause air pollution and
- (8) advise, consult, and cooperate with any governmental or private agency in furthering the purposes of the Air Pollution Act.

The Act further provides that violations shall be prosecuted by the State Attorney General.

In the fields of both air and water pollution control, Ohio cooperates with other States as well as with the Federal government. Ohio is a member of the Ohio River Valley Sanitation Commission (ORSANCO) which is an interstate compact agency created by the States in the Ohio River Valley and the Federal government to maintain and enhance water quality in the streams of the valley. In 1969, Ohio

and West Virginia ratified an interstate compact to establish an interstate agency to prevent, abate, and control air pollution. This compact has been approved by the Federal government. Under the Federal Air Quality Act of 1967, four air quality control regions have been established in Ohio (Cincinnati, Cleveland, Steubenville, and Dayton), and a fifth region will ultimately be established (Toledo).

6.6.7 Pennsylvania

Formal authorization must be obtained from the Public Utility Commission before a thermal power plant and transmission lines can be constructed where eminent domain proceedings are required, or if a municipal system proposes work outside its normal boundaries. A public hearing is required by law in all such cases.

A newly organized Department of Environmental Resources has taken over the authority formerly vested in the Department of Health regarding air and water pollution. The new department's Environmental Quality Board reviews all matters pertaining to the environment and issues construction permits for water related structures.

6.6.8 Wisconsin

Certification is required by the Public Service Commission before any electric utility can construct any generating station, prime mover, or principal steam or electric generating unit, or any equipment designed to change materially the rated or nominal output characteristics of existing generating units.

Certification is also required before any electric utility can construct any electric line which will connect with the system or facilities of another electric utility, or which will bring in a new power supply to its own system in an incorporated city or village or other principal load center. Certification is also necessary if the cost exceeds \$1,000 or 2 percent of the utility's gross electric operating revenues for the last preceding calendar year, whichever is greater.

In 1967 the Wisconsin Legislature created a Department of Natural Resources which has the primary functions of providing an adequate and flexible system for the protection, development and use of forests, fish, game, lakes, streams, plant life, flowers and

other outdoor resources in the State of Wisconsin; and organizing a comprehensive program for the enhancement of the quality, management and protection of all waters of the State, ground and surface, public and private, and other vital environmental factors such as solid waste disposal, quality of the air, protection of shorelines, flood plains, and open spaces.

The Department of Natural Resources, headed by a Natural Resources Board, has approximately 1,400 employees and is organized with a Secretary of Natural Resources and several bureaus and divisions. One of these divisions is the Division of Environmental Protection which has the Air and Water Pollution Control Bureaus. Advisory groups include an Air Pollution Control Council (a group of seven individuals appointed by the Governor which advises on matters pertaining to air pollution and solid waste disposal).

Certain matters relating to radiation are under the jurisdiction of the Wisconsin Department of Health and Social Service which is also organized with a number of bureaus and divisions.

There are two regional organizations operating in the State of Wisconsin having responsibility in environmental matters. The Wisconsin portion of the Minnesota-Wisconsin Boundary Area Commission was created in 1965 and is composed of five members appointed by the Governor with Senate confirmation for staggered 5-year terms. The Commission is assisted by the Legislative Advisory Committee, consisting of 10 legislators, and a Technical Advisory Committee, consisting of two members appointed by the Governor and one member from each of seven State agencies. Their functions are to conduct studies and to develop recommendations relating to the present and future protection, use, and development in the public interest, of the lands, river valleys, and waters which form the boundary between the two States. The second organization, the Wisconsin Great Lakes Compact Commission, was created in 1955. The members of this commission, consisting of five individuals appointed by the Governor, are Wisconsin's representatives on the Great Lakes Commission, the interstate agency carrying out the functions authorized by the compact. The commissioners direct and execute a program of education in support of developmental projects for the St. Lawrence Seaway and the Great Lakes. Their efforts also provide mutual research and discussion

in 14 broad fields of water resource problems.

There are also two control boards in the State. The Milwaukee County Department of Air Pollution Control was created in 1961 to regulate the emission of smoke, solids, liquids, gases, fumes, acids, burning embers, sparks, particulate wastes or dusts, into the open air within the territorial limits of Milwaukee County. In addition the Department is empowered to regulate the construction, reconstruction, repair, use of, additions to processes, control equipment, devices, and the application of fuels and raw materials to equipment and processes. The Milwaukee County Air Pollution Advisory Board was appointed by the County Executive to advise the Director of the Milwaukee County Department of Air Pollution Control and the County Board of Supervisors on technical matters. All of the aforementioned organizations are continuing bodies constituted under specific authority.

6.7 Effects of Legislation on Generating Installations

The increased attention to the environmental impact of thermal and hydroelectric power plants and transmission facilities has caused delays in the installation of required generating capacity. For instance, the first large nuclear plant to be constructed on Lake Michigan, the 812-MW Palisades nuclear plant of the Consumers Power Company, was completed in time for the summer peak load in 1970, and was ready for loading pending receipt of an operational license from AEC. However, the operation license was held up until after July 21 because of a public hearing on June 23 requested by conservation groups concerned with thermal pollution and radioactivity. Several subsequent continuations of the hearings were called and operation of the Palisades Plant was delayed. Under an agreement with the environmentalists blocking AEC's approval of the plant, the utility will construct cooling towers and other facilities, and the environmentalists will withdraw their objections. The utility insists that the pollution control facilities are not required, but agreed to their installation because the delay in operating the plant was costing more than could be saved even if the utility won the dispute. The added facilities will cost approximately \$15 million to construct and are expected to cost \$3 million annually to operate.

The Donald C. Cook 2200-MW nuclear plant in Michigan, scheduled for completion in 1972,

has also come under criticism. At a hearing concerning the Environmental Effects of Energy Generation of Lake Michigan in Grand Rapids, Michigan, on March 30, 1970, conservationists objected to both the potential thermal and radioactive effects of nuclear plants, and they also objected to the effects on adjacent shore areas of jetties built in connection with the plants.

The conferees of the Lake Michigan Enforcement Conference are representatives of the four Lake Michigan States, Illinois, Indiana, Michigan, and Wisconsin, and EPA. The purpose of the Conference is to develop uniform water quality standards for the States bordering Lake Michigan. Recommendations of the conferees would require modification of many existing generating plants and the use of costly supplemental cooling systems on most new plants, as well as expensive back-fittings on some plants under construction. For example, the addition of wet mechanical draft cooling towers to the Zion Nuclear Plant in Illinois would add an estimated 10 to 69 cents per month to the average bill of the utility consumer.

In addition to these postponements, another problem is availability of fuels for generating plants. Although the amount of total fuels may be adequate, the right kind of fuels to comply with local regulations on sulfur content are not always readily obtainable, and prices for "clean" fuels have greatly increased.

6.8 Conclusions

Environmental problems have become a challenge to the electric utility industry. They can be solved, but the costs will be considerable. It is estimated that in 1970 the electric utility industry spent \$250 million on air quality control, \$120 million for water quality control, and \$383 million on underground lines, or a total of approximately three-quarters of a billion dollars. Thus, billions of dollars will be required in the future for protection of the environment, which will increase the cost of power production.

Solutions will also require time and additional research. The recent impetus on immediate remedies to the environmental protection problem have caused disruption to the orderly additions of required generating capacity, which could culminate in an inadequate power supply and in serious power shortages.

Zealous conservationists, public officials, and others, in their eagerness to protect the environment, have sometimes not recognized all aspects of the problem. Permissible rise of water temperature and air contamination standards should consider all relevant uses of the natural resources concerned. The use of a natural resource for the production of electric power is of such importance to the health and well-being of the inhabitants of an area and to the economy that it should be given at least equal consideration with other uses when setting standards which might preclude the development of such power.

Alternatives to each use should be investigated, including associated costs and the short- and long-term benefits or detrimental effects of each. The socioeconomic impact should also be investigated. The ability of the existing power supply to meet the near-future requirements should be established before imposing criteria that would delay the addition of necessary generating capacity.

The proper use of a natural resource dictates its conservation. Since flow-through systems consume less water than other systems, the use of a water body for flow-through cooling may be the best use of that resource. Before requiring the expenditure of large amounts of capital for facilities that may not be required, we should determine whether a crisis is imminent. Current environmental studies, as well as additional ones, including actual monitoring, collection, and analysis of environmental data, should be investigated. If these studies warrant it, generating plants not yet committed to operation can be redesigned to comply with the findings of these investigations and existing ones can be phased out or modified during a transition period.

Although much is known about the control of pollution, there are large gaps in our available knowledge. Additional research and development programs should be initiated. These would aid in eliminating or reducing the adverse effects of power plants on the environment. Such programs could include the following investigations:

- (1) flue gas desulfurization, mine-site coal washing, coal gasification
- (2) water effluent mixing methods and criteria for heat rejection
- (3) beneficial use of waste heat for agricultural and aquicultural purposes, space heating, and use in sewage treatment plants
- (4) undergrounding transmission systems
- (5) the treatment and disposal of gaseous,

liquid, and solid waste of fossil and nuclear plants.

Many of these investigations are being actively pursued. Table 10-15 lists some Lake Michigan thermal effect studies completed and currently under way.

The power supply situation in the Great Lakes Basin, as well as throughout the nation, has recently become extremely tight with the potential threat to shortages in the near future. A significant factor increasing costs and limiting growth of capacity is the vigorous opposition to plans for new power facilities because of their possible effects on air, water,

aesthetics, and land use. To avoid undue delay in construction of necessary facilities, Federal legislation is required to provide the mechanism for resolution of conflicting resources use. There are several bills currently before Congress to obtain this end. If the prosperous growth of the Great Lakes Basin is to continue in the decades ahead, passage of appropriate legislation in the near future is required to provide the legislative framework for public agencies to assure timely public disclosure and review utility plans for consistency with established environmental standards.

TABLE 10-15 Lake Michigan Thermal Effects Studies

Title or Subject of Study	Studies Completed		
	Area Investigated	Study Performed By	Study Dates
Great Lakes Basin study	Lake dynamics-biological, physical, chemical	FWQA	1964
Thermal pollution study	Thermal plume-Waukegan	FWQA	1968
Waukegan-Zion study	Thermal plume-Waukegan	Dr. W. O. Pipes	1968
Waukegan-Zion field sampling	Bottom organisms and temperature measurements	FWQA	1969
Potential Zion effects	Heat and rad-wastes	Dr. L. P. Beer	1968
Waste heat effects at Zion plant	Math model to predict effects	Dr. D. W. Pritchard	1970
Study of Oak Creek plant and vicinity	Biological and water temperature survey	Wisc. Div. of Env. Protection	1970
Study of Traverse City plant	Measurement of thermal plume	Mich. Water Res. Comm.	1968
Study of Campbell plant	Measurement of thermal plume	Mich. Water Res. Comm.	1968
Study of Big Rock plant	Measurement of temperature and biological factors	Mich. Water Res. Comm.	1968-69
Study of Campbell plant	Biological Survey	Mich. Water Res. Comm.	1970
Study of Campbell and Big Rock plants	Infra red aerial survey of thermal plumes	Consumers Pwr. Co.	1969

TABLE 10-15(continued) Lake Michigan Thermal Effects Studies

Studies Under Way			
Title or Subject of Study	Area Investigated	Study Performed By	Study Dates
Continuous monitoring at Waukegan plant	Measure changes in temperature and oxygen	Ind. Bio-Test (Dr. W. O. Pipes)	1970-71
Phytoplankton studies at Waukegan plant	Evaluate thermal shock of algae in condenser	Ind. Bio-Test (Dr. W. O. Pipes)	1970-71
Tank studies on fish at Waukegan plant	Determine fish response to intake and discharge temp.	Ind. Bio-Test (Dr. W. O. Pipes)	1970-71
Preoperational studies at Zion plant	Inventory of biological, physical, chemical factors	Ind. Bio-Test (Dr. W. O. Pipes)	1970
Lake dynamics at Waukegan and Zion	Continuously monitor current, water tempera- ture, meteorology	Ind. Bio-Test (Dr. W. O. Pipes)	1970-72
Zooplankton studies at Waukegan plant	Estimate deleterious level of thermal shock on organisms	Ind. Bio-Test (Dr. W. O. Pipes)	1970-72
Zion organisms study	Background study of organisms at Zion plant	Env. Parameters Res. Organ.	1968-71
Biological measure- ments of Palisades plant	Before and after measure- ments of effects	T. W. Beak Consultants	1968-72
Biological sampling at Campbell plant	Measure biological forms at plant	T. W. Beak Consultants	1968
Ecological studies at Cook plant	Pre and post operational ecological studies	Univ. of Mich. (Dr. J. C. Ayers)	1969

SUMMARY AND CONCLUSIONS

In 1970 there were 365 utilities located either totally or partially within the Power Region. These utilities consisted of 233 municipal and other publicly owned systems, 59 cooperatively owned systems, 63 privately owned systems, and one Federally owned system. During 1970, these utilities produced 156.0 billion kilowatt hours (kWh) of electric energy, slightly less than the Region's requirement of 161.3 billion kWh. The installed capacity amounted to 32.8 million kW, or 4.9 million kW more than the annual peak load of 27.9 million kW.

Bulk power transfers within the Power Region are readily accomplished by means of an existing 345-kV Extra High Voltage (EHV) transmission grid. During the next decade, based on projections made by members of electric utilities within the Region, the existing transmission will be further strengthened by the construction of additional 345-kV lines as well as the construction of 765-kV lines, some of which are already in operation. For purposes of this study, it has been assumed that in the next decade, the pattern of EHV transmission and resulting coordination capability will continue.

Major coordination of the electric supply in the Region is being carried out by five of the nine recently-formed reliability councils, which together encompass the entire U.S. In addition to these, there are numerous smaller coordination and planning groups operating within the Power Region.

The major hydroelectric power has been in the eastern areas of the Power Region. In 1970 the installed hydroelectric capacity located in the Basin totalled 4,067 megawatts (MW). Although there are a number of potential conventional hydroelectric sites in the Region, their economic justification has not been established, and therefore, they have not been included in the future supply. In addition to conventional hydroelectric power, consideration must also be given to the possible development of hydroelectric pumped-storage projects. At the present time there is one existing pumped-storage project in the Region with an installed capability of 240 MW. A 1,872

MW development is under construction. Because of its topography and water resources, New York has numerous potential pumped-storage hydroelectric sites. Because there is a projected need for both peaking and reserve capacity that can be met by such developments, it has been assumed that 960 MW of pumped storage will be developed in the Lake Ontario West river basin group by 2000 and an additional 1,200 MW in the period after 2000. It was also assumed that the Lake Ontario Central river basin group would have an installation of 2,100 MW by 2020. The economic feasibility of these projects has not yet been established. If they are not built, their absence will not materially affect the overall power supply of the Region nor the conclusions of this report.

Thermal-electric generation currently accounts for 83 percent of the Region's electric supply, primarily in the form of fossil-fueled steam-electric generation. Fossil-fueled generation is projected to increase through the next decade, and nuclear generation is projected to become the primary fuel source by the year 2000. This trend is now becoming evident with increasing importance being given nuclear generation in the Power Region.

The Power Region is currently importing a small net amount of electric energy. Because this is only approximately three percent of its energy requirements, and because back and forth transfers occur from year to year, it has been assumed that the Power Region will be self-sufficient in meeting the projected electrical requirements throughout the period of study. Known firm transfers, as indicated in the report, have been accounted for in the determination of the projected power supply. This is expected to result in a net export of electric energy by 2020 of 274 billion kWh, or 11 percent of the power produced in the Region. Based on this and our analysis of the Region requirements, electric power installations and energy production are projected to amount to 459 million kW and 2467 billion kWh by the year 2020. This corresponds to power requirements of 365 million kW and 2193 billion kWh. The average annual compound rate of growth

of the power requirements for the fifty-year period, 1970–2020, is assumed to be approximately 5.3 percent.

In 1970 steam-electric generation located in the Power Region relied almost exclusively on the use of flow-through type condenser cooling systems, a process in which cooling water is diverted from a large lake or river source, passed through the plant's condenser, and returned to the original water source.

Approximately 19 million acre-feet of water were diverted for electric generation in 1970. The consumptive use, resulting from increased evaporation, amounted to 184 thousand acre-feet. Based on continued use of flow-through type cooling as the primary type, diversion could increase to about 250 million acre-feet annually by 2020 with the evaporation loss increasing to 1947 thousand acre-feet.

As an alternative to flow-through cooling, supplemental cooling systems could be used. However, they would involve both higher capital and operating costs. If supplemental cooling systems were used, the amount of diversion required would be greatly reduced, and the evaporation loss would be somewhat greater. Using supplemental cooling, diversion by 2020 would amount to 3963 thousand acre-feet per year and consumptive use to 3032 thousand acre-feet per year.

Supplemental cooling has been used only in areas of limited water availability. It now appears likely that present interest in limiting the impact of thermal discharges will result in reevaluation of the use of supplemental cooling. In the future, the process of reconciling

ecological and environmental values with construction of additional electric generating facilities will require the coordinated joint effort of the power industry and area resource planners. While there will be a sufficient volume of water available within the Great Lakes Basin Power Region to meet the projected water needs for steam-electric generation throughout the study period, it is not yet resolved whether future large generating stations will be able to comply with still-to-be-established water quality criteria if flow-through cooling is used. Failure to arrive at ecological and environmental standards is causing delays in the timely construction of needed generating facilities. The use of a natural resource for production of electric power is of such importance to the health and well-being of the inhabitants of an area and to the economy that it should be given at least equal consideration with other uses when setting standards which might preclude the development of such power. The ability of the existing power supply to meet its near-term requirements should be established before imposing criteria which would delay the addition of necessary generating capacity.

Regardless of the ultimate cooling method that evolves, there is an adequate water supply to develop the needed electric generation to meet the projected requirements of the Great Lakes Basin. The primary requirement to insure a continuing electric power supply in the Great Lakes Basin is the establishment of compatible ecological, environmental, and land use criteria.

GLOSSARY

acre-foot (ac.ft.)—an area of one acre covered to a depth of one foot.

boiler makeup water—water required to replace the loss of circulating water in the boiler system.

British thermal unit (Btu)—the standard unit for measurement of the amount of heat energy, such as the heat content of fuel. Equal to the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

capacity factor—the ratio of the average load on the generating plant for the period of time considered to the capacity rating of the plant.

condenser cooling water—water required to condense the steam after its passage from the steam turbine.

cooling water consumption—the cooling water withdrawn from the source supplying a generating plant which is lost to the atmosphere. Caused primarily by evaporation due to the temperature rise in the cooling water as it passes through the condenser. The amount of consumption (loss) is dependent on the type of cooling employed; flow-through, cooling pond, or cooling tower.

cooling water load—heat energy dissipated by the cooling water.

cooling water required—the amount of water needed to pass through the condensing unit in order to condense the steam to water. This amount is independent of the type of cooling employed for a given temperature rise of the cooling water.

generator efficiency—the ratio of the power output of the generator to the power input.

gross static head—the difference of elevations between the water surfaces of the forebay and tailrace under no-flow conditions.

heat equivalent of electric generator output—the amount of heat energy equivalent to one kilowatt-hour of electric energy. 3413 Btu=one kilowatt-hour of electric energy output of the generator.

heat loss from boiler furnace—heat energy loss from the combustion chamber through the stack. This energy is not part of the cooling water load.

heat loss from electric generator—heat lost in converting the mechanical turbine energy into generator electric energy. This heat energy is generally dissipated by a fluid flowing in a closed circuit which is cooled by water. Thus, it is a part of the cooling water load.

heat rate—a measure of the thermal efficiency of a generating station. It is computed by dividing the total Btu content of the fuel burned (or heat released from a nuclear reactor) by the gross energy generated, generally expressed as Btu per kilowatt-hour.

kilowatt (kW)—the electrical unit of power of rate of doing work, which equals 1,000 watts or a 1.341 horsepower.

kilowatt hour (kWh)—the basic unit of electric energy. It equals one kilowatt of power applied steadily for one hour.

megawatt (MW)—one thousand kilowatts.

megawatt-hour (MWh)—one thousand kilowatt-hours.

net heat rate—a measure of the thermal efficiency of a generating station including station use. It is computed by dividing the total Btu content of the fuel burned (or of heat released from a nuclear reactor) by the net energy generated, generally expressed as Btu per net kilowatt-hour.

peak load—the maximum load in a stated period of time. Usually it is the maximum integrated load over an interval of one hour which occurs during the year, month, week, or day. It is used interchangeably with peak demand.

plant efficiency—the ratio of the energy delivered from the plant to the energy received by it under specified conditions.

reserve capacity—the difference between the peak load and the generating capacity available.

thermal efficiency—the ratio of the amount of energy produced to the total Btu content of the fuel consumed, usually expressed as a heat rate (Btu per kWh).

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ADDENDUM

Tables 10-16 through 10-130 in the Addendum present existing and projected power and water demand for the entire Great Lakes Basin and for each river basin group. Tables

10-131 through 10-170 present the same data by State. Table 10-171 presents undeveloped conventional hydroelectric power sites by river basin group.

TABLE 10-16 Power Requirements and Supply—Great Lakes Basin Power Region

	1965	1970	1980	2000	2020
Annual Peak (MW)	20,641	27,944	50,138	150,769	364,639
Annual Energy Reqmnts. (10 ⁶ kWh)	118,606	161,303	294,807	901,076	2,192,872
Annual Load Factor (%)	65.6	65.9	66.9	68.0	68.5
Installed Capacity (MW)					
Thermal	20,867	28,745	55,447	174,327	449,076
Hydro	4,075	4,067	5,940	6,900	10,200
Total	24,942	32,812	61,387	181,227	459,276
Net Generation (10 ⁶ kWh)					
Thermal	98,538	129,704	287,455	949,461	2,434,475
Hydro	21,060	26,274	25,163	26,761	32,254
Total	119,598	155,978	312,618	976,222	2,466,729

TABLE 10-17 Composition of the Thermal Power Supply—Great Lakes Basin Power Region

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
		<u>1965</u>			<u>1970</u>	
Noncondensing	561	24	269	1,736	11	1,744
Fossil Fuel	97,796	54	20,523	123,702	56	25,173
Nuclear	181	28	75	4,266	27	1,828
Total	98,538	54	20,867	129,704	52	28,745
		<u>1980</u>			<u>2000</u>	
Noncondensing	5,761	21	3,190	26,283	20	14,948
Fossil Fuel	145,565	51	32,482	73,763	28	29,670
Nuclear	136,129	78	19,775	849,415	75	129,709
Total	287,455	59	55,447	949,461	62	174,327
		<u>2020</u>				
Noncondensing	75,333	20	42,858			
Fossil Fuel	36,090	43	9,500			
Nuclear	2,323,052	67	396,718			
Total	2,434,475	62	449,076			

TABLE 10-18 Steam-Electric Generation by Type of Cooling—Great Lakes Basin Power Region

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	96,798	1,179	97,977	96,798	1,179	97,977
1970	126,517	1,451	127,968	126,517	1,451	127,968
1980	263,161	18,533	281,694	141,317	140,377	281,694
2000	904,814	18,364	923,178	45,807	877,371	923,178
2020	2,343,859	15,283	2,359,142	---	2,359,142	2,359,142

Condenser Cooling Water Requirements
(acre-feet per year)

1965	12,864,399	171,684	13,036,083	12,864,399	171,684	13,036,083
1970	19,303,707	241,490	19,545,197	19,303,707	241,490	19,545,197
1980	35,193,304	2,890,192	38,083,496	17,306,138	20,777,358	38,083,496
2000	116,631,208	2,386,045	119,017,253	5,466,093	113,551,160	119,017,253
2020	249,707,982	1,630,238	251,338,220	---	251,338,220	251,338,220

Required Diversions
(acre-feet per year)

1965	12,864,399	2,750	12,867,149	12,864,399	2,750	12,867,149
1970	19,303,707	3,863	19,307,570	19,303,707	3,863	19,307,570
1980	35,193,304	45,886	35,239,190	17,306,138	322,744	17,628,882
2000	116,631,208	38,032	116,669,240	5,466,093	1,777,751	7,243,844
2020	249,707,982	26,167	249,734,149	---	3,962,527	3,962,527

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-19 Cooling Water Consumption—Great Lakes Basin Power Region

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
1965	99,563	2,104	101,667	99,563	2,104	101,667
1970	181,077	2,956	184,033	181,077	2,956	184,033
1980	268,604	35,108	303,712	131,822	246,985	378,807
2000	896,698	29,098	925,796	41,922	1,360,177	1,402,099
2020	1,927,275	20,021	1,947,296	-	3,031,774	3,031,774

TABLE 10-20 Summary of Steam-Electric Power Water Use—Great Lakes Basin Power Region

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
1965	13,036,083	12,867,149	101,667	13,036,083	12,867,149	101,667
1970	19,545,197	19,307,570	184,033	19,545,197	19,307,570	184,033
1980	38,083,496	35,239,190	303,712	38,083,496	17,628,882	378,807
2000	119,017,253	116,669,240	925,796	119,017,253	7,243,844	1,402,099
2020	251,338,220	249,734,149	1,947,296	251,338,220	3,962,527	3,031,774

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-21 Power Requirements and Supply—River Basin Group 1.1

	1965	1970	1980	2000	2020
Annual Peak (MW)	314	510	980	3,500	8,760
Annual Energy Reqmnts. (10 ⁶ kWh)	1,673	2,946	5,700	20,500	51,500
Annual Load Factor (%)	60.8	65.9	66.2	66.7	66.9
Installed Capacity (MW)					
Thermal	380	404	436	3,941	9,906
Hydro	88	88	88	88	88
Total	468	492	524	4,029	9,994
Net Generation (10 ⁶ kWh)					
Thermal	1,398	1,920	2,100	20,261	50,572
Hydro	518	451	429	429	429
Total	1,916	2,371	2,529	20,690	51,001

TABLE 10-22 Composition of the Thermal Power Supply—River Basin Group 1.1

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
		1965			1970	
Noncondensing	21	20	12	22	17	15
Fossil Fuel	1,377	43	368	1,898	56	389
Nuclear	---	---	---	---	---	---
Total	1,398	42	380	1,920	54	404
		1980			2000	
Noncondensing	24	20	14	339	20	193
Fossil Fuel	2,076	56	422	2,923	25	1,329
Nuclear	---	---	---	16,999	80	2,419
Total	2,100	55	436	20,261	59	3,941
		2020				
Noncondensing	2,006	20	1,142			
Fossil Fuel	---	---	---			
Nuclear	48,566	63	8,764			
Total	50,572	58	9,906			

TABLE 10-23 Steam-Electric Generation by Type of Cooling—River Basin Group 1.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	1,377	-	1,377	1,377	-	1,377
1970	1,898	-	1,898	1,898	-	1,898
1980	2,076	-	2,076	1,848	228	2,076
2000	19,922	-	19,922	-	19,922	19,922
2020	48,566	-	48,566	-	48,566	48,566

Condenser Cooling Water Requirements
(acre-feet per year)

1965	256,752	-	256,752	256,752	-	256,752
1970	349,365	-	349,365	349,365	-	349,365
1980	226,429	-	226,429	201,561	24,868	226,429
2000	2,530,070	-	2,530,070	-	2,530,070	2,530,070
2020	5,180,535	-	5,180,535	-	5,180,535	5,180,535

Required Diversions
(acre-feet per year)

1965	256,752	-	256,752	256,752	-	256,752
1970	349,365	-	349,365	349,365	-	349,365
1980	226,429	-	226,429	201,561	397	201,958
2000	2,530,070	-	2,530,070	-	40,331	40,331
2020	5,180,535	-	5,180,535	-	83,153	83,153

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-24 Cooling Water Consumption—River Basin Group 1.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
1965	1,957	-	1,957	1,957	-	1,957
1970	2,666	-	2,666	2,666	-	2,666
1980	1,728	-	1,728	1,538	304	1,842
2000	19,411	-	19,411	-	30,858	30,858
2020	39,946	-	39,946	-	63,621	63,621

TABLE 10-25 Summary of Steam-Electric Power Water Use—River Basin Group 1.1

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
1965	256,752	256,752	1,957	256,752	256,752	1,957
1970	349,365	349,365	2,666	349,365	349,365	2,666
1980	226,429	226,429	1,728	226,429	201,958	1,842
2000	2,530,070	2,530,070	19,411	2,530,070	40,331	30,858
2020	5,180,535	5,180,535	39,946	5,180,535	83,153	63,621

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-26 Power Requirements and Supply—River Basin Group 1.2

	<u>1965</u>	<u>1970</u>	<u>1980</u>	<u>2000</u>	<u>2020</u>
Annual Peak (MW)	199	283	510	1,600	3,860
Annual Energy Reqmnts. (10 ⁶ kWh)	1,153	1,614	3,100	9,800	23,800
Annual Load Factor (%)	66.1	65.1	69.2	69.7	70.2
Installed Capacity (MW)					
Thermal	185	255	490	1,805	4,367
Hydro	42	42	42	42	42
Total	<u>227</u>	<u>297</u>	<u>532</u>	<u>1,847</u>	<u>4,409</u>
Net Generation (10 ⁶ kWh)					
Thermal	955	1,412	2,538	8,029	22,987
Hydro	<u>185</u>	<u>174</u>	<u>174</u>	<u>174</u>	<u>174</u>
Total	<u>1,140</u>	<u>1,586</u>	<u>2,712</u>	<u>8,203</u>	<u>23,161</u>

TABLE 10-27 Composition of the Thermal Power Supply—River Basin Group 1.2

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	71	19	42	22	6	40
Fossil Fuel	884	71	143	1,390	74	215
Nuclear	-	-	-	-	-	-
Total	<u>955</u>	<u>59</u>	<u>185</u>	<u>1,412</u>	<u>63</u>	<u>255</u>
	<u>1980</u>			<u>2000</u>		
Noncondensing	148	20	84	220	20	125
Fossil Fuel	2,390	67	406	1,821	25	828
Nuclear	-	-	-	<u>5,988</u>	<u>80</u>	<u>852</u>
Total	<u>2,538</u>	<u>59</u>	<u>490</u>	<u>8,029</u>	<u>51</u>	<u>1,805</u>
	<u>2020</u>					
Noncondensing	796	20	453			
Fossil Fuel	-	-	-			
Nuclear	<u>22,191</u>	<u>65</u>	<u>3,914</u>			
Total	<u>22,987</u>	<u>60</u>	<u>4,367</u>			

TABLE 10-28 Steam-Electric Generation by Type of Cooling—River Basin Group 1.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	884	-	884	884	-	884
1970	1,390	-	1,390	1,390	-	1,390
1980	2,390	-	2,390	1,176	1,214	2,390
2000	7,809	-	7,809	202	7,607	7,809
2020	22,191	-	22,191	-	22,191	22,191

Condenser Cooling Water Requirements
(acre-feet per year)

1965	147,838	-	147,838	147,838	-	147,838
1970	228,266	-	228,266	228,266	-	228,266
1980	260,677	-	260,677	128,266	132,411	260,677
2000	972,306	-	972,306	20,694	951,612	972,306
2020	2,367,114	-	2,367,114	-	2,367,114	2,367,114

Required Diversions
(acre-feet per year)

1965	147,838	-	147,838	147,838	-	147,838
1970	228,266	-	228,266	228,266	-	228,266
1980	260,677	-	260,677	128,266	2,119	130,385
2000	972,306	-	972,306	20,694	15,176	35,870
2020	2,367,114	-	2,367,114	-	37,994	37,994

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-29 Cooling Water Consumption—River Basin Group 1.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	1,131	-	1,131	1,131	-	1,131
1970	1,741	-	1,741	1,741	-	1,741
1980	1,989	-	1,989	979	1,621	2,600
2000	7,457	-	7,457	158	11,611	11,769
2020	18,252	-	18,252	-	29,070	29,070

TABLE 10-30 Summary of Steam-Electric Power Water Use—River Basin Group 1.2

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	147,838	147,838	1,131	147,838	147,838	1,131
1970	228,266	228,266	1,741	228,266	228,266	1,741
1980	260,677	260,677	1,989	260,677	130,385	2,600
2000	972,306	972,306	7,457	972,306	35,870	11,769
2020	2,367,114	2,367,114	18,252	2,367,114	37,994	29,070

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-31 Power Requirements and Supply—River Basin Group 2.1

	<u>1965</u>	<u>1970</u>	<u>1980</u>	<u>2000</u>	<u>2020</u>
Annual Peak (MW)	895	1,248	2,290	7,000	16,810
Annual Energy Reqmnts. (10 ⁶ kWh)	5,189	7,581	13,900	43,200	104,100
Annual Load Factor (%)	66.2	69.3	69.1	70.3	70.5
Installed Capacity (MW)					
Thermal	675	1,560	2,695	8,786	21,155
Hydro	<u>152</u>	<u>150</u>	<u>150</u>	<u>150</u>	<u>150</u>
Total	827	1,710	2,845	8,936	21,305
Net Generation (10 ⁶ kWh)					
Thermal	2,427	4,648	15,149	47,968	109,593
Hydro	<u>728</u>	<u>712</u>	<u>712</u>	<u>712</u>	<u>712</u>
Total	3,155	5,360	15,861	48,680	110,305

TABLE 10-32 Composition of the Thermal Power Supply—River Basin Group 2.1

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	2	5	5	85	21	47
Fossil Fuel	2,425	41	670	4,530	52	989
Nuclear	-	-	-	33	1	524
Total	<u>2,427</u>	<u>41</u>	<u>675</u>	<u>4,648</u>	<u>34</u>	<u>1,560</u>
	<u>1980</u>			<u>2000</u>		
Noncondensing	246	20	140	666	20	379
Fossil Fuel	4,130	46	1,022	5,364	25	2,439
Nuclear	<u>10,773</u>	<u>80</u>	<u>1,533</u>	<u>41,938</u>	<u>80</u>	<u>5,968</u>
Total	15,149	64	2,695	47,968	62	8,786
	<u>2020</u>					
Noncondensing	2,192	20	1,248			
Fossil Fuel	-	-	-			
Nuclear	<u>107,401</u>	<u>61</u>	<u>19,907</u>			
Total	109,593	59	21,155			

TABLE 10-33 Steam-Electric Generation by Type of Cooling—River Basin Group 2.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	2,425	-	2,425	2,425	-	2,425
1970	4,563	-	4,563	4,563	-	4,563
1980	14,903	-	14,903	7,539	7,364	14,903
2000	47,302	-	47,302	726	46,576	47,302
2020	107,401	-	107,401	-	107,401	107,401

Condenser Cooling Water Requirements
(acre-feet per year)

1965	407,301	-	407,301	407,301	-	407,301
1970	749,565	-	749,565	749,565	-	749,565
1980	2,207,858	-	2,207,858	1,013,381	1,194,477	2,207,858
2000	6,052,646	-	6,052,646	74,379	5,978,267	6,052,646
2020	11,456,465	-	11,456,465	-	11,456,465	11,456,465

Required Diversions
(acre-feet per year)

1965	407,301	-	407,301	407,301	-	407,301
1970	749,565	-	749,565	749,565	-	749,565
1980	2,207,858	-	2,207,858	1,013,381	18,885	1,032,266
2000	6,052,646	-	6,052,646	74,379	95,303	169,682
2020	11,456,465	-	11,456,465	-	183,888	183,888

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-34 Cooling Water Consumption—River Basin Group 2.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	4,435	-	4,435	4,435	-	4,435
1970	5,720	-	5,720	5,720	-	5,720
1980	16,883	-	16,883	7,745	14,499	22,244
2000	46,447	-	46,447	568	72,917	73,485
2020	88,337	-	88,337	-	140,695	140,695

TABLE 10-35 Summary of Steam-Electric Power Water Use—River Basin Group 2.1

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	407,301	407,301	4,435	407,301	407,301	4,435
1970	749,565	749,565	5,720	749,565	749,565	5,720
1980	2,207,858	2,207,858	16,883	2,207,858	1,032,266	22,244
2000	6,052,646	6,052,646	46,447	6,052,646	169,682	73,485
2020	11,456,465	11,456,465	88,337	11,456,465	183,888	140,695

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-36 Power Requirements and Supply—River Basin Group 2.2 (Total)

	1965	1970	1980	2000	2020
Annual Peak (MW)	2,002	2,935	5,960	18,900	46,160
Annual Energy Reqmts. (10 ⁶ kWh)	11,382	16,281	35,462	114,600	281,200
Annual Load Factor (%)	64.9	63.3	67.7	69.0	69.4
Installed Capacity (MW)					
Thermal	5,059	6,408	11,686	36,576	104,904
Hydro	-	-	-	-	-
Total	5,059	6,408	11,686	36,576	104,904
Net Generation (10 ⁶ kWh)					
Thermal	22,994	29,769	58,920	208,044	599,222
Hydro	-	-	-	-	-
Total	22,994	29,769	58,920	208,044	599,222

TABLE 10-37 Composition of the Thermal Power Supply—River Basin Group 2.2 (Total)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	27	51	6	300	12	283
Fossil Fuel	22,967	52	5,053	29,469	55	6,125
Nuclear	-	-	-	-	-	-
Total	22,994	52	5,059	29,769	53	6,408
	<u>1980</u>			<u>2000</u>		
Noncondensing	1,358	20	775	3,216	20	1,830
Fossil Fuel	32,362	50	7,325	12,125	22	6,219
Nuclear	25,200	80	3,586	192,703	77	28,527
Total	58,920	57	11,686	208,044	65	36,576
	<u>2020</u>					
Noncondensing	11,156	20	6,350			
Fossil Fuel	-	-	-			
Nuclear	588,066	68	98,554			
Total	599,222	65	104,904			

TABLE 10-38 Steam-Electric Generation by Type of Cooling—River Basin Group 2.2 (Total)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	22,967	-	22,967	22,967	-	22,967
1970	29,469	-	29,469	29,469	-	29,469
1980	57,562	-	57,562	22,040	35,522	57,562
2000	204,828	-	204,828	2,076	202,752	204,828
2020	588,066	-	588,066	-	588,066	588,066

Condenser Cooling Water Requirements
(acre-feet per year)

1965	2,904,324	-	2,904,324	2,904,324	-	2,904,324
1970	3,594,164	-	3,594,164	3,594,164	-	3,594,164
1980	7,640,599	-	7,640,599	2,403,903	5,236,696	7,640,599
2000	26,528,694	-	26,528,694	212,687	26,316,007	26,528,694
2020	62,729,000	-	62,729,000	-	62,729,000	62,729,000

Required Diversions
(acre-feet per year)

1965	2,904,324	-	2,904,324	2,904,324	-	2,904,324
1970	3,594,164	-	3,594,164	3,594,164	-	3,594,164
1980	7,640,599	-	7,640,599	2,403,903	83,226	2,487,129
2000	26,528,694	-	26,528,694	212,687	419,451	632,138
2020	62,729,000	-	62,729,000	-	1,006,870	1,006,870

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-39 Cooling Water Consumption—River Basin Group 2.2 (Total)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	22,257	-	22,257	22,257	-	22,257
1970	27,429	-	27,429	27,429	-	27,429
1980	58,387	-	58,387	18,346	63,677	82,023
2000	203,628	-	203,628	1,624	320,927	322,551
2020	483,603	-	483,603	-	770,367	770,367

TABLE 10-40 Summary of Steam-Electric Power Water Use—River Basin Group 2.2 (Total)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	2,904,324	2,904,324	22,257	2,904,324	2,904,324	22,257
1970	3,594,164	3,594,164	27,429	3,594,164	3,594,164	27,429
1980	7,640,599	7,640,599	58,387	7,640,599	2,487,129	82,023
2000	26,528,694	26,528,694	203,628	26,528,694	632,138	322,551
2020	62,729,000	62,729,000	483,603	62,729,000	1,006,870	770,367

¹ 1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

² 1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-41 Power Requirements and Supply—River Basin Group 2.2 (Wisconsin)

	1965	1970	1980	2000	2020
Annual Peak (MW)	1,284	1,780	3,270	10,010	24,110
Annual Energy Reqmnts. (10 ⁶ kWh)	6,752	9,109	18,000	56,100	135,600
Annual Load Factor (%)	60.0	58.4	62.7	63.8	64.0
Installed Capacity (MW)					
Thermal	2,160	2,809	4,497	11,523	27,508
Hydro	-	-	-	-	-
Total	2,160	2,809	4,497	11,523	27,508
Net Generation (10 ⁶ kWh)					
Thermal	8,736	12,762	20,159	55,291	138,797
Hydro	-	-	-	-	-
Total	8,736	12,762	20,159	55,291	138,797

TABLE 10-42 Composition of the Thermal Power Supply—River Basin Group 2.2 (Wisconsin)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	27	51	6	56	8	84
Fossil Fuel	8,709	46	2,154	12,706	53	2,725
Nuclear	-	-	-	-	-	-
Total	8,736	46	2,160	12,762	52	2,809
	<u>1980</u>			<u>2000</u>		
Noncondensing	1,209	20	690	1,986	20	1,130
Fossil Fuel	13,328	50	3,007	8,985	25	4,086
Nuclear	5,622	80	800	44,320	80	6,307
Total	20,159	51	4,497	55,291	55	11,523
	<u>2020</u>					
Noncondensing	6,588	20	3,750			
Fossil Fuel	-	-	-			
Nuclear	132,209	63	23,758			
Total	138,797	57	27,508			

TABLE 10-43 Steam-Electric Generation by Type of Cooling—River Basin Group 2.2 (Wisconsin)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	8,709	-	8,709	8,709	-	8,709
1970	12,706	-	12,706	12,706	-	12,706
1980	18,950	-	18,950	12,669	6,281	18,950
2000	53,305	-	53,305	1,286	52,019	53,305
2020	132,209	-	132,209	-	132,209	132,209

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,025,961	-	1,025,961	1,025,961	-	1,025,961
1970	1,469,957	-	1,469,957	1,469,957	-	1,469,957
1980	2,370,802	-	2,370,802	1,381,808	988,994	2,370,802
2000	6,736,183	-	6,736,183	131,751	6,604,432	6,736,183
2020	14,102,734	-	14,102,734	-	14,102,734	14,102,734

Required Diversions
(acre-feet per year)

1965	1,025,961	-	1,025,961	1,025,961	-	1,025,961
1970	1,469,957	-	1,469,957	1,469,957	-	1,469,957
1980	2,370,802	-	2,370,802	1,381,808	15,700	1,397,508
2000	6,736,183	-	6,736,183	131,751	105,301	237,052
2020	14,102,734	-	14,102,734	-	226,365	226,365

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-44 Cooling Water Consumption—River Basin Group 2.2 (Wisconsin)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	7,848	-	7,848	7,848	-	7,848
1970	11,218	-	11,218	11,218	-	11,218
1980	18,110	-	18,110	10,546	12,012	22,558
2000	51,677	-	51,677	1,006	80,567	81,573
2020	108,660	-	108,660	-	173,194	173,194

TABLE 10-45 Summary of Steam-Electric Power Water Use—River Basin Group 2.2 (Wisconsin)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,025,961	1,025,961	7,848	1,025,961	1,025,961	7,848
1970	1,469,957	1,469,957	11,218	1,469,957	1,469,957	11,218
1980	2,370,802	2,370,802	18,110	2,370,802	1,397,508	22,558
2000	6,736,183	6,736,183	51,677	6,736,183	237,052	81,573
2020	14,102,734	14,102,734	108,660	14,102,734	226,365	173,194

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-46 Power Requirements and Supply—River Basin Group 2.2 (Illinois)

	1965	1970	1980	2000	2020
Annual Peak (MW)	-	-	-	-	-
Annual Energy Reqmnts. (10 ⁶ kWh)	-	-	-	-	-
Annual Load Factor (%)	-	-	-	-	-
Installed Capacity (MW)					
Thermal	1,108	1,181	2,928	17,673	59,039
Hydro	-	-	-	-	-
Total	<u>1,108</u>	<u>1,181</u>	<u>2,928</u>	<u>17,673</u>	<u>59,039</u>
Net Generation (10 ⁶ kWh)					
Thermal	4,946	5,212	18,030	116,430	363,022
Hydro	-	-	-	-	-
Total	<u>4,946</u>	<u>5,212</u>	<u>18,030</u>	<u>116,430</u>	<u>363,022</u>

TABLE 10-47 Composition of the Thermal Power Supply—River Basin Group 2.2 (Illinois)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
		<u>1965</u>			<u>1970</u>	
Noncondensing	-	-	-	87	9	113
Fossil Fuel	4,946	51	1,108	5,125	55	1,068
Nuclear	-	-	-	-	-	-
Total	<u>4,946</u>	<u>51</u>	<u>1,108</u>	<u>5,212</u>	<u>50</u>	<u>1,181</u>
		<u>1980</u>			<u>2000</u>	
Noncondensing	-	-	-	-	-	-
Fossil Fuel	3,273	45	828	-	-	-
Nuclear	<u>14,757</u>	<u>80</u>	<u>2,100</u>	<u>116,430</u>	<u>75</u>	<u>17,673</u>
Total	<u>18,030</u>	<u>70</u>	<u>2,928</u>	<u>116,430</u>	<u>75</u>	<u>17,673</u>
		<u>2020</u>				
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	<u>363,022</u>	<u>70</u>	<u>59,039</u>			
Total	<u>363,022</u>	<u>70</u>	<u>59,039</u>			

TABLE 10-48 Steam-Electric Generation by Type of Cooling—River Basin Group 2.2 (Illinois)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	4,946	-	4,946	4,946	-	4,946
1970	5,125	-	5,125	5,125	-	5,125
1980	18,030	-	18,030	3,273	14,757	18,030
2000	116,430	-	116,430	-	116,430	116,430
2020	363,022	-	363,022	-	363,022	363,022

Condenser Cooling Water Requirements
(acre-feet per year)

1965	662,840	-	662,840	662,840	-	662,840
1970	649,440	-	649,440	649,440	-	649,440
1980	2,764,295	-	2,764,295	356,986	2,407,309	2,764,295
2000	15,277,945	-	15,277,945	-	15,277,945	15,277,945
2020	38,723,557	-	38,723,557	-	38,723,557	38,723,557

Required Diversions
(acre-feet per year)

1965	662,840	-	662,840	662,840	-	662,840
1970	649,440	-	649,440	649,440	-	649,440
1980	2,764,295	-	2,764,295	356,986	38,189	395,175
2000	15,277,945	-	15,277,945	-	243,478	243,478
2020	38,723,557	-	38,723,557	-	621,556	621,556

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-49 Cooling Water Consumption—River Basin Group 2.2 (Illinois)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	5,099	-	5,099	5,099	-	5,099
1970	4,956	-	4,956	4,956	-	4,956
1980	21,141	-	21,141	2,724	29,219	31,943
2000	117,303	-	117,303	-	186,288	186,288
2020	298,586	-	298,586	-	475,559	475,559

TABLE 10-50 Summary of Steam-Electric Power Water Use—River Basin Group 2.2 (Illinois)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	662,840	662,840	5,099	662,840	662,840	5,099
1970	649,440	649,440	4,956	649,440	649,440	4,956
1980	2,764,295	2,764,295	21,141	2,764,295	395,175	31,943
2000	15,277,945	15,277,945	117,303	15,277,945	243,478	186,288
2020	38,723,557	38,723,557	298,586	38,723,557	621,556	475,559

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-51 Power Requirements and Supply—River Basin Group 2.2 (Indiana-Michigan)

	1965	1970	1980	2000	2020
Annual Peak (MW)	718	1,155	2,690	8,890	22,050
Annual Energy Reqmts. (10 ⁶ kWh)	4,630	7,172	17,462	58,500	145,600
Annual Load Factor (%)	73.6	70.9	73.9	74.9	75.2
Installed Capacity (MW)					
Thermal	1,791	2,418	4,261	7,380	18,357
Hydro	-	-	-	-	-
Total	1,791	2,418	4,261	7,380	18,357
Net Generation (10 ⁶ kWh)					
Thermal	9,312	11,795	20,731	36,323	97,403
Hydro	-	-	-	-	-
Total	9,312	11,795	20,731	36,323	97,403

TABLE 10-52 Composition of the Thermal Power Supply—River Basin Group 2.2 (Indiana-Michigan)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	-	-	-	157	21	86
Fossil Fuel	9,312	59	1,791	11,638	57	2,332
Nuclear	-	-	-	-	-	-
Total	9,312	59	1,791	11,795	56	2,418
	<u>1980</u>			<u>2000</u>		
Noncondensing	149	20	85	1,230	20	700
Fossil Fuel	15,761	51	3,490	3,140	17	2,133
Nuclear	4,821	80	686	31,953	80	4,547
Total	20,731	55	4,261	36,323	56	7,380
	<u>2020</u>					
Noncondensing	4,568	20	2,600			
Fossil Fuel	-	-	-			
Nuclear	92,835	67	15,757			
Total	97,403	60	18,357			

TABLE 10-53 Steam-Electric Generation by Type of Cooling—River Basin Group 2.2 (Indiana-Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	9,312	-	9,312	9,312	-	9,312
1970	11,638	-	11,638	11,638	-	11,638
1980	20,582	-	20,582	6,098	14,484	20,582
2000	35,093	-	35,093	790	34,303	35,093
2020	92,835	-	92,835	-	92,835	92,835

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,215,523	-	1,215,523	1,215,523	-	1,215,523
1970	1,474,767	-	1,474,767	1,474,767	-	1,474,767
1980	2,505,502	-	2,505,502	665,109	1,840,393	2,505,502
2000	4,514,566	-	4,514,566	80,936	4,433,630	4,514,566
2020	9,902,709	-	9,902,709	-	9,902,709	9,902,709

Required Diversions
(acre-feet per year)

1965	1,215,523	-	1,215,523	1,215,523	-	1,215,523
1970	1,474,767	-	1,474,767	1,474,767	-	1,474,767
1980	2,505,502	-	2,505,502	665,109	29,337	694,446
2000	4,514,566	-	4,514,566	80,936	70,672	151,608
2020	9,902,709	-	9,902,709	-	158,949	158,949

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-54 Cooling Water Consumption—River Basin Group 2.2 (Indiana-Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	9,310	-	9,310	9,310	-	9,310
1970	11,255	-	11,255	11,255	-	11,255
1980	19,136	-	19,136	5,076	22,446	27,522
2000	34,648	-	34,648	618	54,072	54,690
2020	76,357	-	76,357	-	121,614	121,614

TABLE 10-55 Summary of Steam-Electric Power Water Use—River Basin Group 2.2 (Indiana-Michigan)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,215,523	1,215,523	9,310	1,215,523	1,215,523	9,310
1970	1,474,767	1,474,767	11,255	1,474,767	1,474,767	11,255
1980	2,505,502	2,505,502	19,136	2,505,502	694,446	27,522
2000	4,514,566	4,514,566	34,648	4,514,566	151,608	54,690
2020	9,902,709	9,902,709	76,357	9,902,709	158,949	121,614

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-56 Power Requirements and Supply—River Basin Group 2.3

	1965	1970	1980	2000	2020
Annual Peak (MW)	2,089	2,896	5,320	16,150	38,870
Annual Energy Reqmts. (10 ⁶ kWh)	11,803	16,268	30,700	96,000	234,000
Annual Load Factor (%)	64.5	64.1	65.7	67.7	68.5
Installed Capacity (MW)					
Thermal	1,412	2,333	5,055	22,305	52,868
Hydro	42	36	36	36	36
Total	1,454	2,369	5,091	22,341	52,904
Net Generation (10 ⁶ kWh)					
Thermal	5,022	8,870	28,630	122,369	282,932
Hydro	167	125	138	138	138
Total	5,189	8,995	28,768	122,507	283,070

TABLE 10-57 Composition of the Thermal Power Supply—River Basin Group 2.3

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	155	22	80	180	9	217
Fossil Fuel	4,867	42	1,332	8,690	47	2,116
Nuclear	-	-	-	-	-	-
Total	5,022	41	1,412	8,870	43	2,333
	<u>1980</u>			<u>2000</u>		
Noncondensing	339	20	193	2,663	20	1,516
Fossil Fuel	7,125	44	1,850	3,427	17	2,327
Nuclear	21,166	80	3,012	116,279	72	18,462
Total	28,630	64	5,055	122,369	62	22,305
	<u>2020</u>					
Noncondensing	11,156	20	6,350			
Fossil Fuel	-	-	-			
Nuclear	271,776	67	46,518			
Total	282,932	61	52,868			

TABLE 10-58 Steam-Electric Generation by Type of Cooling—River Basin Group 2.3

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	3,688	1,179	4,867	3,688	1,179	4,867
1970	7,239	1,451	8,690	7,239	1,451	8,690
1980	25,829	2,462	28,291	4,663	23,628	28,291
2000	116,072	3,634	119,706	722	118,984	119,706
2020	256,493	15,283	271,776	-	271,776	271,776

Condenser Cooling Water Requirements
(acre-feet per year)

1965	490,582	171,684	662,266	490,582	171,684	662,266
1970	1,204,787	241,490	1,446,277	1,204,787	241,490	1,446,277
1980	3,961,403	268,530	4,229,933	508,593	3,721,340	4,229,933
2000	15,156,051	453,175	15,609,226	73,969	15,535,257	15,609,226
2020	27,360,108	1,630,238	28,990,346	-	28,990,346	28,990,346

Required Diversions
(acre-feet per year)

1965	490,582	2,750	493,332	490,582	2,750	493,332
1970	1,204,787	3,863	1,208,650	1,204,787	3,863	1,208,650
1980	3,961,403	4,296	3,965,699	508,593	59,071	567,664
2000	15,156,051	7,228	15,163,279	73,969	247,595	321,564
2020	27,360,108	26,167	27,386,275	-	465,327	465,327

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-59 Cooling Water Consumption—River Basin Group 2.3

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	3,754	2,104	5,858	3,754	2,104	5,858
1970	9,194	2,956	12,150	9,194	2,956	12,150
1980	30,296	3,287	33,583	3,881	45,196	49,077
2000	116,355	5,530	121,885	565	189,438	190,003
2020	210,965	20,021	230,986	-	356,027	356,027

TABLE 10-60 Summary of Steam-Electric Power Water Use—River Basin Group 2.3

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	662,266	493,332	5,858	662,266	493,332	5,858
1970	1,446,277	1,208,650	12,150	1,446,277	1,208,650	12,150
1980	4,229,933	3,965,699	33,583	4,229,933	567,664	49,077
2000	15,609,226	15,163,279	121,885	15,609,226	321,564	190,003
2020	28,990,346	27,386,275	230,986	28,990,346	465,327	356,027

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-61 Power Requirements and Supply—River Basin Group 2.4 (Total)

	1965	1970	1980	2000	2020
Annual Peak (MW)	419	556	1,030	3,000	7,070
Annual Energy Reqmts. (10 ⁶ kWh)	2,331	3,175	5,900	18,000	43,200
Annual Load Factor (%)	63.5	65.2	65.2	68.3	69.6
Installed Capacity (MW)					
Thermal	671	758	722	1,058	5,110
Hydro	91	87	1,960	1,960	1,960
Total	762	845	2,682	3,018	7,070
Net Generation (10 ⁶ kWh)					
Thermal	3,257	3,775	3,038	5,793	31,646
Hydro	314	273	2,527	2,527	2,527
Total	3,571	4,048	5,565	8,320	34,173

TABLE 10-62 Composition of the Thermal Power Supply—River Basin Group 2.4 (Total)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	1965			1970		
Noncondensing	83	35	27	30	5	67
Fossil Fuel	2,993	60	569	3,383	63	616
Nuclear	181	28	75	362	55	75
Total	3,257	55	671	3,775	57	758
	1980			2000		
Noncondensing	86	20	49	44	20	25
Fossil Fuel	2,425	46	598	401	17	272
Nuclear	527	80	75	5,348	80	761
Total	3,038	48	722	5,793	62	1,058
	2020					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	31,646	71	5,110			
Total	31,646	71	5,110			

TABLE 10-63 Steam-Electric Generation by Type of Cooling—River Basin Group 2.4 (Total)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	3,174	-	3,174	3,174	-	3,174
1970	3,745	-	3,745	3,745	-	3,745
1980	2,952	-	2,952	2,952	-	2,952
2000	5,749	-	5,749	69	5,680	5,749
2020	31,646	-	31,646	-	31,646	31,646

Condenser Cooling Water Requirements
(acre-feet per year)

1965	440,603	-	440,603	440,603	-	440,603
1970	527,908	-	527,908	527,908	-	527,908
1980	350,465	-	350,465	350,465	-	350,465
2000	742,847	-	742,847	7,069	735,778	742,847
2020	3,375,679	-	3,375,679	-	3,375,679	3,375,679

Required Diversions
(acre-feet per year)

1965	440,603	-	440,603	440,603	-	440,603
1970	527,908	-	527,908	527,908	-	527,908
1980	350,465	-	350,465	350,465	-	350,465
2000	742,847	-	742,847	7,069	11,728	18,797
2020	3,375,679	-	3,375,679	-	54,183	54,183

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-64 Cooling Water Consumption—River Basin Group 2.4 (Total)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	3,366	-	3,366	3,366	-	3,366
1970	4,029	-	4,029	4,029	-	4,029
1980	2,677	-	2,677	2,677	-	2,677
2000	5,702	-	5,702	54	8,973	9,027
2020	26,029	-	26,029	-	41,456	41,456

TABLE 10-65 Summary of Steam-Electric Power Water Use—River Basin Group 2.4 (Total)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	440,603	440,603	3,366	440,603	440,603	3,366
1970	527,908	527,908	4,029	527,908	527,908	4,029
1980	350,465	350,465	2,677	350,465	350,465	2,677
2000	742,847	742,847	5,702	742,847	18,797	9,027
2020	3,375,679	3,375,679	26,029	3,375,679	54,183	41,456

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-66 Power Requirements and Supply—River Basin Group 2.4 (Lower Michigan)

	1965	1970	1980	2000	2020
Annual Peak (MW)	368	505	910	2,600	6,130
Annual Energy Reqmnts. (10^6 kWh)	2,086	2,924	5,300	15,900	38,300
Annual Load Factor (%)	64.7	66.1	66.3	69.6	71.1
Installed Capacity (MW)					
Thermal	640	727	691	1,058	5,110
Hydro	89	85	1,958	1,958	1,958
Total	729	812	2,649	3,016	7,068
Net Generation (10^6 kWh)					
Thermal	3,132	3,625	2,944	5,793	31,646
Hydro	309	268	2,522	2,522	2,522
Total	3,441	3,893	5,466	8,315	34,168

TABLE 10-67 Composition of the Thermal Power Supply—River Basin Group 2.4 (Lower Michigan)

	Energy (10^6 kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10^6 kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	83	38	25	29	5	65
Fossil Fuel	2,868	61	540	3,234	63	587
Nuclear	181	28	75	362	55	75
Total	3,132	56	640	3,625	57	727
	<u>1980</u>			<u>2000</u>		
Noncondensing	82	20	47	44	20	25
Fossil Fuel	2,335	47	569	401	17	272
Nuclear	527	80	75	5,348	80	761
Total	2,944	49	691	5,793	62	1,058
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	31,646	71	5,110			
Total	31,646	71	5,110			

TABLE 10-68 Steam-Electric Generation by Type of Cooling—River Basin Group 2.4 (Lower Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	3,049	-	3,049	3,049	-	3,049
1970	3,596	-	3,596	3,596	-	3,596
1980	2,862	-	2,862	2,862	-	2,862
2000	5,749	-	5,749	69	5,680	5,749
2020	31,646	-	31,646	-	31,646	31,646

Condenser Cooling Water Requirements
(acre-feet per year)

1965	415,625	-	415,625	415,625	-	415,625
1970	499,166	-	499,166	499,166	-	499,166
1980	340,649	-	340,649	340,649	-	340,649
2000	742,847	-	742,847	7,069	735,778	742,847
2020	3,375,679	-	3,375,679	-	3,375,679	3,375,679

Required Diversions
(acre-feet per year)

1965	415,625	-	415,625	415,625	-	415,625
1970	499,166	-	499,166	499,166	-	499,166
1980	340,649	-	340,649	340,649	-	340,649
2000	742,847	-	742,847	7,069	11,728	18,797
2020	3,375,679	-	3,375,679	-	54,183	54,183

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-69 Cooling Water Consumption—River Basin Group 2.4 (Lower Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	3,174	-	3,174	3,174	-	3,174
1970	3,810	-	3,810	3,810	-	3,810
1980	2,602	-	2,602	2,602	-	2,602
2000	5,702	-	5,702	54	8,973	9,027
2020	26,029	-	26,029	-	41,456	41,456

TABLE 10-70 Summary of Steam-Electric Power Water Use—River Basin Group 2.4 (Lower Michigan)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	415,625	415,625	3,174	415,625	415,625	3,174
1970	499,166	499,166	3,810	499,166	499,166	3,810
1980	340,649	340,649	2,602	340,649	340,649	2,602
2000	742,847	742,847	5,702	742,847	18,797	9,027
2020	3,375,679	3,375,679	26,029	3,375,679	54,183	41,456

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-71 Power Requirements and Supply—River Basin Group 2.4 (Upper Michigan)

	1965	1970	1980	2000	2020
Annual Peak (MW)	51	51	120	400	940
Annual Energy Reqmts. (10 ⁶ kWh)	245	251	600	2,100	4,900
Annual Load Factor (%)	54.8	56.2	56.9	59.8	59.3
Installed Capacity (MW)					
Thermal	31	31	31	-	-
Hydro	2	2	2	2	2
Total	33	33	33	2	2
Net Generation (10 ⁶ kWh)					
Thermal	125	150	94	-	-
Hydro	5	5	5	5	5
Total	130	155	99	5	5

TABLE 10-72 Composition of the Thermal Power Supply—River Basin Group 2.4 (Upper Michigan)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	-	-	2	1	6	2
Fossil Fuel	125	49	29	149	59	29
Nuclear	-	-	-	-	-	-
Total	125	46	31	150	55	31
	<u>1980</u>			<u>2000</u>		
Noncondensing	4	23	2	-	-	-
Fossil Fuel	90	35	29	-	-	-
Nuclear	-	-	-	-	-	-
Total	94	35	31	-	-	-
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	-	-	-			
Total	-	-	-			

TABLE 10-73 Steam-Electric Generation by Type of Cooling—River Basin Group 2.4 (Upper Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	125	-	125	125	-	125
1970	149	-	149	149	-	149
1980	90	-	90	90	-	90
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Condenser Cooling Water Requirements
(acre-feet per year)

1965	24,978	-	24,978	24,978	-	24,978
1970	28,742	-	28,742	28,742	-	28,742
1980	9,816	-	9,816	9,816	-	9,816
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Required Diversions
(acre-feet per year)

1965	24,978	-	24,978	24,978	-	24,978
1970	28,742	-	28,742	28,742	-	28,742
1980	9,816	-	9,816	9,816	-	9,816
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-74 Cooling Water Consumption—River Basin Group 2.4 (Upper Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	192	-	192	192	-	192
1970	219	-	219	219	-	219
1980	75	-	75	75	-	75
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

TABLE 10-75 Summary of Steam-Electric Power Water Use—River Basin Group 2.4 (Upper Michigan)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	24,978	24,978	192	24,978	24,978	192
1970	28,742	28,742	219	28,742	28,742	219
1980	9,816	9,816	75	9,816	9,816	75
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-76 Power Requirements and Supply—River Basin Group 3.1 (Total)

	1965	1970	1980	2000	2020
Annual Peak (MW)	208	270	520	1,520	3,580
Annual Energy Reqmts. (10 ⁶ kWh)	1,032	1,392	2,700	8,000	19,300
Annual Load Factor (%)	56.6	58.9	59.1	59.9	61.4
Installed Capacity (MW)					
Thermal	9	99	117	110	-
Hydro	<u>110</u>	<u>110</u>	<u>110</u>	<u>110</u>	<u>110</u>
Total	119	209	227	220	110
Net Generation (10 ⁶ kWh)					
Thermal	10	172	200	191	-
Hydro	<u>629</u>	<u>602</u>	<u>606</u>	<u>606</u>	<u>606</u>
Total	639	774	806	797	606

TABLE 10-77 Composition of the Thermal Power Supply—River Basin Group 3.1 (Total)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	10	13	9	172	20	99
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	<u>10</u>	<u>13</u>	<u>9</u>	<u>172</u>	<u>20</u>	<u>99</u>
	<u>1980</u>			<u>2000</u>		
Noncondensing	200	20	117	191	20	110
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	<u>200</u>	<u>20</u>	<u>117</u>	<u>191</u>	<u>20</u>	<u>110</u>
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	-	-	-			
Total	<u>-</u>	<u>-</u>	<u>-</u>			

TABLE 10-78 Steam-Electric Generation by Type of Cooling—River Basin Group 3.1 (Total)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Condenser Cooling Water Requirements
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Required Diversions
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-79 Cooling Water Consumption—River Basin Group 3.1 (Total)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

TABLE 10-80 Summary of Steam-Electric Power Water Use—River Basin Group 3.1 (Total)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-81 Power Requirements and Supply—River Basin Group 3.1 (Lower Michigan)

	1965	1970	1980	2000	2020
Annual Peak (MW)	156	213	390	1,100	2,600
Annual Energy Reqmnts. (10 ⁶ kWh)	843	1,167	2,200	6,400	15,500
Annual Load Factor (%)	61.7	62.5	64.2	66.2	67.9
Installed Capacity (MW)					
Thermal	4	95	113	109	-
Hydro	50	50	50	50	50
Total	54	145	163	159	50
Net Generation (10 ⁶ kWh)					
Thermal	10	172	200	191	-
Hydro	189	183	175	175	175
Total	199	355	375	366	175

TABLE 10-82 Composition of the Thermal Power Supply—River Basin Group 3.1 (Lower Michigan)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	10	29	4	172	21	95
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	10	29	4	172	21	95
	<u>1980</u>			<u>2000</u>		
Noncondensing	200	20	113	191	20	109
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	200	20	113	191	20	109
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	-	-	-			
Total	-	-	-			

TABLE 10-83 Steam-Electric Generation by Type of Cooling—River Basin Group 3.1 (Lower Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Condenser Cooling Water Requirements
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Required Diversions
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-84 Cooling Water Consumption—River Basin Group 3.1 (Lower Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

TABLE 10-85 Summary of Steam-Electric Power Water Use—River Basin Group 3.1 (Lower Michigan)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-86 Power Requirements and Supply—River Basin Group 3.1 (Upper Michigan)

	1965	1970	1980	2000	2020
Annual Peak (MW)	52	57	130	420	980
Annual Energy Reqmnts. (10 ⁶ kWh)	189	225	500	1,600	3,800
Annual Load Factor (%)	41.5	45.1	43.8	43.4	44.1
Installed Capacity (MW)					
Thermal	5	4	4	1	-
Hydro	60	60	60	60	60
Total	65	64	64	61	60
Net Generation (10 ⁶ kWh)					
Thermal	-	-	-	-	-
Hydro	440	419	431	431	431
Total	440	419	431	431	431

TABLE 10-87 Composition of the Thermal Power Supply—River Basin Group 3.1 (Upper Michigan)

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	-	-	5	-	-	4
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	-	-	5	-	-	4
	<u>1980</u>			<u>2000</u>		
Noncondensing	-	-	4	-	-	1
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	-	-	4	-	-	1
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	-	-	-			
Total	-	-	-			

TABLE 10-88 Steam-Electric Generation by Type of Cooling—River Basin Group 3.1 (Upper Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Condenser Cooling Water Requirements
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Required Diversions
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹ 1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

² 1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-89 Cooling Water Consumption—River Basin Group 3.1 (Upper Michigan)

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

TABLE 10-90 Summary of Steam-Electric Power Water Use—River Basin Group 3.1 (Upper Michigan)

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-91 Power Requirements and Supply—River Basin Group 3.2

	1965	1970	1980	2000	2020
Annual Peak (MW)	1,034	1,393	2,550	7,300	17,240
Annual Energy Reqmnts. (10 ⁶ kWh)	5,805	8,027	14,900	44,300	106,400
Annual Load Factor (%)	64.1	65.8	66.5	69.1	70.3
Installed Capacity (MW)					
Thermal	1,314	1,608	6,887	26,808	75,157
Hydro	11	10	10	10	10
Total	1,325	1,618	6,897	26,818	75,167
Net Generation (10 ⁶ kWh)					
Thermal	6,670	7,340	36,546	148,765	416,084
Hydro	38	36	23	23	23
Total	6,708	7,376	36,569	148,788	416,107

TABLE 10-92 Composition of the Thermal Power Supply—River Basin Group 3.2

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	1965			1970		
Noncondensing	81	40	23	223	11	242
Fossil Fuel	6,589	58	1,291	7,117	59	1,366
Nuclear	-	-	-	-	-	-
Total	6,670	58	1,314	7,340	52	1,608
	1980			2000		
Noncondensing	1,091	20	621	4,457	20	2,537
Fossil Fuel	9,588	42	2,585	2,152	17	1,441
Nuclear	25,867	80	3,681	142,156	71	22,830
Total	36,546	60	6,887	148,765	63	26,808
	2020					
Noncondensing	12,652	20	7,202			
Fossil Fuel	-	-	-			
Nuclear	403,432	68	67,955			
Total	416,084	63	75,157			

TABLE 10-93 Steam-Electric Generation by Type of Cooling—River Basin Group 3.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	6,589	-	6,589	6,589	-	6,589
1970	7,117	-	7,117	7,117	-	7,117
1980	25,749	9,706	35,455	3,877	31,578	35,455
2000	135,695	8,613	144,308	180	144,128	144,308
2020	403,432	-	403,432	-	403,432	403,432

Condenser Cooling Water Requirements
(acre-feet per year)

1965	781,914	-	781,914	781,914	-	781,914
1970	839,023	-	839,023	839,023	-	839,023
1980	3,682,107	1,583,340	5,265,447	422,864	4,842,583	5,265,447
2000	17,743,984	1,130,198	18,874,182	18,441	18,855,741	18,874,182
2020	43,034,091	-	43,034,091	-	43,034,091	43,034,091

Required Diversions
(acre-feet per year)

1965	781,914	-	781,914	781,914	-	781,914
1970	839,023	-	839,023	839,023	-	839,023
1980	3,682,107	25,118	3,707,225	422,864	76,905	499,769
2000	17,743,984	18,012	17,761,996	18,441	300,509	318,950
2020	43,034,091	-	43,034,091	-	690,744	690,744

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-94 Cooling Water Consumption—River Basin Group 3.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	5,948	-	5,948	5,948	-	5,948
1970	6,403	-	6,403	6,403	-	6,403
1980	28,150	19,218	47,368	3,227	58,841	62,068
2000	137,237	13,781	151,018	141	229,923	230,064
2020	335,756	-	335,756	-	528,496	528,496

TABLE 10-95 Summary of Steam-Electric Power Water Use—River Basin Group 3.2

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	781,914	781,914	5,948	781,914	781,914	5,948
1970	839,023	839,023	6,403	839,023	839,023	6,403
1980	5,265,447	3,707,225	47,368	5,265,447	499,769	62,068
2000	18,874,182	17,761,996	151,018	18,874,182	318,950	230,064
2020	43,034,091	43,034,091	335,756	43,034,091	690,744	528,496

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-96 Power Requirements and Supply—River Basin Group 4.1

	1965	1970	1980	2000	2020
Annual Peak (MW)	4,208	5,805	10,360	29,750	70,140
Annual Energy Reqmnts. (10 ⁶ kWh)	23,388	32,455	59,900	178,800	429,100
Annual Load Factor (%)	63.4	63.8	65.8	68.4	69.6
Installed Capacity (MW)					
Thermal	4,800	6,560	11,028	17,980	27,600
Hydro	-	-	-	-	-
Total	4,800	6,560	11,028	17,980	27,600
Net Generation (10 ⁶ kWh)					
Thermal	25,130	33,998	43,876	84,853	141,119
Hydro	-	-	-	-	-
Total	25,130	33,998	43,876	84,853	141,119

TABLE 10-97 Composition of the Thermal Power Supply—River Basin Group 4.1

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	8	46	2	547	13	477
Fossil Fuel	25,122	60	4,798	33,439	63	6,013
Nuclear	-	-	-	12	2	70
Total	25,130	60	4,800	33,998	59	6,560
	<u>1980</u>			<u>2000</u>		
Noncondensing	1,662	20	946	3,066	20	1,745
Fossil Fuel	34,168	44	8,937	7,310	17	4,895
Nuclear	8,046	80	1,145	74,477	75	11,340
Total	43,876	45	11,028	84,853	54	17,980
	<u>2020</u>					
Noncondensing	6,148	20	3,500			
Fossil Fuel	-	-	-			
Nuclear	134,971	64	24,100			
Total	141,119	58	27,600			

TABLE 10-98 Steam-Electric Generation by Type of Cooling—River Basin Group 4.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	25,122	-	25,122	25,122	-	25,122
1970	33,451	-	33,451	33,451	-	33,451
1980	42,214	-	42,214	15,464	26,750	42,214
2000	81,787	-	81,787	2,786	79,001	81,787
2020	134,971	-	134,971	-	134,971	134,971

Condenser Cooling Water Requirements
(acre-feet per year)

1965	3,287,081	-	3,287,081	3,287,081	-	3,287,081
1970	4,312,973	-	4,312,973	4,312,973	-	4,312,973
1980	5,039,248	-	5,039,248	1,713,256	3,325,992	5,039,248
2000	10,521,782	-	10,521,782	285,426	10,236,356	10,521,782
2020	14,397,357	-	14,397,357	-	14,397,357	14,397,357

Required Diversions
(acre-feet per year)

1965	3,287,081	-	3,287,081	3,287,081	-	3,287,081
1970	4,312,973	-	4,312,973	4,312,973	-	4,312,973
1980	5,039,248	-	5,039,248	1,713,256	53,043	1,766,299
2000	10,521,782	-	10,521,782	285,426	163,161	448,587
2020	14,397,357	-	14,397,357	-	231,093	231,093

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-99 Cooling Water Consumption—River Basin Group 4.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	25,067	-	25,067	25,067	-	25,067
1970	32,915	-	32,915	32,915	-	32,915
1980	38,482	-	38,482	13,077	40,584	53,661
2000	80,752	-	80,752	2,178	124,836	127,014
2020	111,014	-	111,014	-	176,812	176,812

TABLE 10-100 Summary of Steam-Electric Power Water Use—River Basin Group 4.1

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	3,287,081	3,287,081	25,067	3,287,081	3,287,081	25,067
1970	4,312,973	4,312,973	32,915	4,312,973	4,312,973	32,915
1980	5,039,248	5,039,248	38,482	5,039,248	1,766,299	53,661
2000	10,521,782	10,521,782	80,752	10,521,782	448,587	127,014
2020	14,397,357	14,397,357	111,014	14,397,357	231,093	176,812

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-101 Power Requirements and Supply—River Basin Group 4.2

	1965	1970	1980	2000	2020
Annual Peak (MW)	1,753	2,583	4,660	15,858	39,896
Annual Energy Reqmnts. (10 ⁶ kWh)	10,398	16,460	27,689	94,332	237,318
Annual Load Factor (%)	67.7	72.7	67.6	67.7	67.7
Installed Capacity (MW)					
Thermal	907	1,282	2,103	15,537	38,750
Hydro	-	-	-	-	-
Total	907	1,282	2,103	15,537	38,750
Net Generation (10 ⁶ kWh)					
Thermal	4,080	4,994	12,409	82,884	208,108
Hydro	-	-	-	-	-
Total	4,080	4,994	12,409	82,884	208,108

TABLE 10-102 Composition of the Thermal Power Supply—River Basin Group 4.2

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	57	15	42	84	7	134
Fossil Fuel	4,023	53	865	4,910	49	1,148
Nuclear	-	-	-	-	-	-
Total	4,080	51	907	4,994	44	1,282
	<u>1980</u>			<u>2000</u>		
Noncondensing	226	20	129	3,540	20	2,015
Fossil Fuel	5,818	62	1,068	3,345	17	2,271
Nuclear	6,365	80	906	75,999	77	11,251
Total	12,409	67	2,103	82,884	61	15,537
	<u>2020</u>					
Noncondensing	8,879	20	5,054			
Fossil Fuel	-	-	-			
Nuclear	199,229	67	33,696			
Total	208,108	61	38,750			

TABLE 10-103 Steam Electric Generation by Type of Cooling—River Basin Group 4.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	4,023	-	4,023	4,023	-	4,023
1970	4,910	-	4,910	4,910	-	4,910
1980	5,818	6,365	12,183	5,818	6,365	12,183
2000	73,227	6,117	79,344	3,345	75,999	79,344
2020	199,229	-	199,229	-	199,229	199,229

Condenser Cooling Water Requirements
(acre-feet per year)

1965	563,889	-	563,889	563,889	-	563,889
1970	998,975	-	998,975	998,975	-	998,975
1980	634,569	1,038,322	1,672,891	634,569	1,038,322	1,672,891
2000	9,512,612	802,672	10,315,284	342,696	9,972,588	10,315,284
2020	21,251,757	-	21,251,757	-	21,251,757	21,251,757

Required Diversions
(acre-feet per year)

1965	563,889	-	563,889	563,889	-	563,889
1970	998,975	-	998,975	998,975	-	998,975
1980	634,569	16,472	651,041	634,569	16,472	651,041
2000	9,512,612	12,792	9,525,404	342,696	158,933	501,629
2020	21,251,757	-	21,251,757	-	341,114	341,114

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-104 Cooling Water Consumption—River Basin Group 4.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	4,303	-	4,303	4,303	-	4,303
1970	11,976	-	11,976	11,976	-	11,976
1980	4,829	12,603	17,432	4,829	12,603	17,432
2000	73,190	9,787	82,977	2,606	121,601	124,207
2020	163,368	-	163,368	-	260,990	260,990

TABLE 10-105 Summary of Steam-Electric Power Water Use—River Basin Group 4.2

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	563,889	563,889	4,303	563,889	563,889	4,303
1970	998,975	998,975	11,976	998,975	998,975	11,976
1980	1,672,891	651,041	17,432	1,672,891	651,041	17,432
2000	10,315,284	9,525,404	82,977	10,315,284	501,629	124,207
2020	21,251,757	21,251,757	163,368	21,251,757	341,114	260,990

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-106 Power Requirements and Supply—River Basin Group 4.3

	1965	1970	1980	2000	2020
Annual Peak (MW)	2,795	3,707	6,638	21,172	52,700
Annual Energy Reqmnts. (10 ⁶ kWh)	16,296	21,941	39,549	126,112	313,938
Annual Load Factor (%)	66.6	67.6	67.8	67.8	67.8
Installed Capacity (MW)					
Thermal	2,595	3,419	4,069	16,119	45,300
Hydro	-	-	-	-	-
Total	2,595	3,419	4,069	16,119	45,300
Net Generation (10 ⁶ kWh)					
Thermal	11,624	14,267	24,898	89,536	235,653
Hydro	-	-	-	-	-
Total	11,624	14,267	24,898	89,536	235,653

TABLE 10-107 Composition of the Thermal Power Supply—River Basin Group 4.3

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	36	29	14	51	8	74
Fossil Fuel	11,588	51	2,581	14,216	49	3,345
Nuclear	-	-	-	-	-	-
Total	11,624	51	2,595	14,267	48	3,419
	<u>1980</u>			<u>2000</u>		
Noncondensing	296	46	74	5,044	20	2,871
Fossil Fuel	24,602	70	3,995	2,281	17	1,549
Nuclear	-	-	-	82,211	80	11,699
Total	24,898	70	4,069	89,536	63	16,119
	<u>2020</u>					
Noncondensing	13,352	20	7,600			
Fossil Fuel	-	-	-			
Nuclear	222,301	67	37,700			
Total	235,653	59	45,300			

TABLE 10-108 Steam-Electric Generation by Type of Cooling—River Basin Group 4.3

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	11,588	-	11,588	11,588	-	11,588
1970	14,216	-	14,216	14,216	-	14,216
1980	24,602	-	24,602	24,602	-	24,602
2000	84,492	-	84,492	2,281	82,211	84,492
2020	222,301	-	222,301	-	222,301	222,301

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,564,380	-	1,564,380	1,564,380	-	1,564,380
1970	2,854,353	-	2,854,353	2,854,353	-	2,854,353
1980	2,683,340	-	2,683,340	2,683,340	-	2,683,340
2000	11,021,415	-	11,021,415	233,688	10,787,727	11,021,415
2020	23,712,848	-	23,712,848	-	23,712,848	23,712,848

Required Diversions
(acre-feet per year)

1965	1,564,380	-	1,564,380	1,564,380	-	1,564,380
1970	2,854,353	-	2,854,353	2,854,353	-	2,854,353
1980	2,683,340	-	2,683,340	2,683,340	-	2,683,340
2000	11,021,415	-	11,021,415	233,688	171,920	405,608
2020	23,712,848	-	23,712,848	-	380,617	380,617

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-109 Cooling Water Consumption—River Basin Group 4.3

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	11,935	-	11,935	11,935	-	11,935
1970	34,544	-	34,544	34,544	-	34,544
1980	20,120	-	20,120	20,120	-	20,120
2000	84,812	-	84,812	1,779	131,538	133,317
2020	182,289	-	182,289	-	291,214	291,214

TABLE 10-110 Summary of Steam-Electric Power Water Use—River Basin Group 4.3

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,564,380	1,564,380	11,935	1,564,380	1,564,380	11,935
1970	2,854,353	2,854,353	34,544	2,854,353	2,854,353	34,544
1980	2,683,340	2,683,340	20,120	2,683,340	2,683,340	20,120
2000	11,021,415	11,021,415	84,812	11,021,415	405,608	133,317
2020	23,712,848	23,712,848	182,289	23,712,848	380,617	291,214

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-111 Power Requirements and Supply—River Basin Group 4.4

	1965	1970	1980	2000	2020
Annual Peak (MW)	1,280	1,594	2,286	6,154	14,631
Annual Energy Reqmnts. (10 ⁶ kWh)	7,004	9,443	12,782	34,483	81,833
Annual Load Factor (%)	62.5	67.6	63.7	63.8	63.7
Installed Capacity (MW)					
Thermal	1,579	1,580	2,680	8,794	29,809
Hydro	- ^{1/}	- ^{1/}	- ^{1/}	- ^{1/}	- ^{1/}
Total	1,579	1,580	2,680	8,794	29,809
Net Generation (10 ⁶ kWh)					
Thermal	8,517	7,765	15,615	57,116	165,196
Hydro	2	2	2	2	2
Total	8,519	7,767	15,617	57,118	165,198

TABLE 10-112 Composition of the Thermal Power Supply—River Basin Group 4.4

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	1965			1970		
Noncondensing	10	29	4	12	27	5
Fossil Fuel	8,507	62	1,575	7,753	56	1,575
Nuclear	-	-	-	-	-	-
Total	8,517	62	1,579	7,765	56	1,580
	1980			2000		
Noncondensing	9	20	5	842	20	468
Fossil Fuel	7,878	57	1,575	17,130	71	2,734
Nuclear	7,728	80	1,100	39,144	80	5,592
Total	15,615	66	2,680	57,116	74	8,794
	2020					
Noncondensing	2,079	20	1,155			
Fossil Fuel	15,950	43	4,200			
Nuclear	147,167	69	24,454			
Total	165,196	63	29,809			

^{1/} Less than 1 megawatt.

TABLE 10-113 Steam-Electric Generation by Type of Cooling—River Basin Group 4.4

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	8,507	-	8,507	8,507	-	8,507
1970	7,753	-	7,753	7,753	-	7,753
1980	15,606	-	15,606	7,878	7,728	15,606
2000	56,274	-	56,274	-	56,274	56,274
2020	163,117	-	163,117	-	163,117	163,117

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,148,445	-	1,148,445	1,148,445	-	1,148,445
1970	1,646,704	-	1,646,704	1,646,704	-	1,646,704
1980	2,119,922	-	2,119,922	859,253	1,260,669	2,119,922
2000	6,891,445	-	6,891,445	-	6,891,445	6,891,445
2020	17,262,042	-	17,262,042	-	17,262,042	17,262,042

Required Diversions
(acre-feet per year)

1965	1,148,445	-	1,148,445	1,148,445	-	1,148,445
1970	1,646,704	-	1,646,704	1,646,704	-	1,646,704
1980	2,119,922	-	2,119,922	859,253	12,626	871,879
2000	6,891,445	-	6,891,445	-	103,905	103,905
2020	17,262,042	-	17,262,042	-	276,991	276,991

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-114 Cooling Water Consumption—River Basin Group 4.4

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	8,762	-	8,762	8,762	-	8,762
1970	20,090	-	20,090	20,090	-	20,090
1980	16,199	-	16,199	6,539	9,660	16,199
2000	52,896	-	52,896	-	79,499	79,499
2020	132,640	-	132,640	-	211,929	211,929

TABLE 10-115 Summary of Steam-Electric Power Water Use—River Basin Group 4.4

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,148,445	1,148,445	8,762	1,148,445	1,148,445	8,762
1970	1,646,704	1,646,704	20,090	1,646,704	1,646,704	20,090
1980	2,119,922	2,119,922	16,199	2,119,922	871,879	16,199
2000	6,891,445	6,891,445	52,896	6,891,445	103,905	79,499
2020	17,262,042	17,262,042	132,640	17,262,042	276,991	211,929

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-116 Power Requirements and Supply—River Basin Group 5.1

	1965	1970	1980	2000	2020
Annual Peak (MW)	1,986	2,315	3,715	10,010	23,712
Annual Energy Reqmnts. (10 ⁶ kWh)	10,821	12,270	20,804	55,703	131,985
Annual Load Factor (%)	62.2	60.5	63.8	63.4	63.4
Installed Capacity (MW)					
Thermal	471	1,025	2,025	7,125	18,809
Hydro	<u>2,255</u>	<u>2,251</u>	<u>2,251</u>	<u>3,211</u>	<u>4,411</u>
Total	2,726	3,276	4,276	10,336	23,220
Net Generation (10 ⁶ kWh)					
Thermal	2,299	4,200	11,633	35,031	95,214
Hydro	<u>11,679</u>	<u>15,584</u>	<u>12,434</u>	<u>14,032</u>	<u>16,028</u>
Total	13,978	19,784	24,067	49,063	111,242

TABLE 10-117 Composition of the Thermal Power Supply—River Basin Group 5.1

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
		<u>1965</u>			<u>1970</u>	
Noncondensing	-	-	-	7	2	38
Fossil Fuel	2,299	56	471	2,021	49	470
Nuclear	-	-	-	<u>2,172</u>	<u>48</u>	<u>517</u>
Total	<u>2,299</u>	<u>56</u>	<u>471</u>	4,200	47	1,025
		<u>1980</u>			<u>2000</u>	
Noncondensing	67	20	38	1,330	20	764
Fossil Fuel	2,264	55	470	5,566	52	1,210
Nuclear	<u>9,302</u>	<u>70</u>	<u>1,517</u>	<u>28,135</u>	<u>62</u>	<u>5,151</u>
Total	11,633	65	2,025	35,031	56	7,125
		<u>2020</u>				
Noncondensing	3,274	20	1,875			
Fossil Fuel	7,980	43	2,100			
Nuclear	<u>83,960</u>	<u>64</u>	<u>14,834</u>			
Total	95,214	58	18,809			

TABLE 10-118 Steam-Electric Generation by Type of Cooling—River Basin Group 5.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	2,299	-	2,299	2,299	-	2,299
1970	4,193	-	4,193	4,193	-	4,193
1980	11,566	-	11,566	11,566	-	11,566
2000	33,701	-	33,701	8,286	25,415	33,701
2020	91,940	-	91,940	-	91,940	91,940

Condenser Cooling Water Requirements
(acre-feet per year)

1965	310,365	-	310,365	310,365	-	310,365
1970	825,441	-	825,441	825,441	-	825,441
1980	1,764,369	-	1,764,369	1,764,369	-	1,764,369
2000	4,262,111	-	4,262,111	1,087,289	3,174,822	4,262,111
2020	9,738,372	-	9,738,372	-	9,738,372	9,738,372

Required Diversions
(acre-feet per year)

1965	310,365	-	310,365	310,365	-	310,365
1970	825,441	-	825,441	825,441	-	825,441
1980	1,764,369	-	1,764,369	1,764,369	-	1,764,369
2000	4,262,111	-	4,262,111	1,087,289	31,875	1,119,164
2020	9,738,372	-	9,738,372	-	97,805	97,805

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-119 Cooling Water Consumption—River Basin Group 5.1

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	2,368	-	2,368	2,368	-	2,368
1970	10,070	-	10,070	10,070	-	10,070
1980	13,507	-	13,507	13,507	-	13,507
2000	32,757	-	32,757	8,369	24,388	32,757
2020	74,832	-	74,832	-	74,832	74,832

TABLE 10-120 Summary of Steam-Electric Power Water Use—River Basin Group 5.1

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	310,365	310,365	2,368	310,365	310,365	2,368
1970	825,441	825,441	10,070	825,441	825,441	10,070
1980	1,764,369	1,764,369	13,507	1,764,369	1,764,369	13,507
2000	4,262,111	4,262,111	32,757	4,262,111	1,119,164	32,757
2020	9,738,372	9,738,372	74,832	9,738,372	97,805	74,832

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-121 Power Requirements and Supply—River Basin Group 5.2

	1965	1970	1980	2000	2020
Annual Peak (MW)	799	1,079	1,894	5,008	11,897
Annual Energy Reqmnts. (10 ⁶ kWh)	5,390	6,582	11,235	29,610	69,930
Annual Load Factor (%)	77.0	69.6	67.5	67.3	66.9
Installed Capacity (MW)					
Thermal	807	1,453	5,454	7,383	15,341
Hydro	76	86	86	86	2,186
Total	883	1,539	5,540	7,469	17,527
Net Generation (10 ⁶ kW)					
Thermal	4,155	6,574	31,903	38,621	76,149
Hydro	247	298	266	266	3,763
Total	4,402	6,872	32,169	38,887	79,912

TABLE 10-122 Composition of the Thermal Power Supply—River Basin Group 5.2

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	-	-	-	1	2	5
Fossil Fuel	4,155	59	807	4,886	69	806
Nuclear	-	-	-	1,687	30	642
Total	4,155	59	807	6,574	52	1,453
	<u>1980</u>			<u>2000</u>		
Noncondensing	9	20	5	665	20	370
Fossil Fuel	10,739	55	2,229	9,918	52	2,156
Nuclear	21,155	75	3,220	28,038	66	4,857
Total	31,903	67	5,454	38,621	60	7,383
	<u>2020</u>					
Noncondensing	1,643	20	929			
Fossil Fuel	12,160	43	3,200			
Nuclear	62,346	63	11,212			
Total	76,149	57	15,341			

TABLE 10-123 Steam-Electric Generation by Type of Cooling—River Basin Group 5.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	4,155	-	4,155	4,155	-	4,155
1970	6,573	-	6,573	6,573	-	6,573
1980	31,894	-	31,894	31,894	-	31,894
2000	37,956	-	37,956	25,134	12,822	37,956
2020	74,506	-	74,506	-	74,506	74,506

Condenser Cooling Water Requirements
(acre-feet per year)

1965	560,925	-	560,925	560,925	-	560,925
1970	1,172,183	-	1,172,183	1,172,183	-	1,172,183
1980	4,622,318	-	4,622,318	4,622,318	-	4,622,318
2000	4,695,245	-	4,695,245	3,109,755	1,585,490	4,695,245
2020	7,842,614	-	7,842,614	-	7,842,614	7,842,614

Required Diversions
(acre-feet per year)

1965	560,925	-	560,925	560,925	-	560,925
1970	1,172,183	-	1,172,183	1,172,183	-	1,172,183
1980	4,622,318	-	4,622,318	4,622,318	-	4,622,318
2000	4,695,245	-	4,695,245	3,109,755	17,864	3,127,619
2020	7,842,614	-	7,842,614	-	112,748	112,748

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-124 Cooling Water Consumption—River Basin Group 5.2

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	4,280	-	4,280	4,280	-	4,280
1970	14,300	-	14,300	14,300	-	14,300
1980	35,357	-	35,357	35,357	-	35,357
2000	36,054	-	36,054	23,880	13,668	37,548
2020	60,244	-	60,244	-	86,265	86,265

TABLE 10-125 Summary of Steam-Electric Power Water Use—River Basin Group 5.2

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	560,925	560,925	4,280	560,925	560,925	4,280
1970	1,172,183	1,172,183	14,300	1,172,183	1,172,183	14,300
1980	4,622,318	4,622,318	35,357	4,622,318	4,622,318	35,357
2000	4,695,245	4,695,245	36,054	4,695,245	3,127,619	37,548
2020	7,842,614	7,842,614	60,244	7,842,614	112,748	86,265

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-126 Power Requirements and Supply—River Basin Group 5.3

	1965	1970	1980	2000	2020
Annual Peak (MW)	660	770	1,425	3,847	9,313
Annual Energy Reqmnts. (10 ⁶ kWh)	4,941	4,868	10,486	27,636	65,268
Annual Load Factor (%)	85.5	72.2	83.8	81.8	79.8
Installed Capacity (MW)					
Thermal	3	1	-	-	-
Hydro	<u>1,208</u>	<u>1,207</u>	<u>1,207</u>	<u>1,207</u>	<u>1,207</u>
Total	1,211	1,208	1,207	1,207	1,207
Net Generation (10 ⁶ kWh)					
Thermal	-	-	-	-	-
Hydro	<u>6,553</u>	<u>8,017</u>	<u>7,852</u>	<u>7,852</u>	<u>7,852</u>
Total	6,553	8,017	7,852	7,852	7,852

TABLE 10-127 Composition of the Thermal Power Supply—River Basin Group 5.3

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	-	-	3	-	-	1
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	-	-	<u>3</u>	-	-	<u>1</u>
	<u>1980</u>			<u>2000</u>		
Noncondensing	-	-	-	-	-	-
Fossil Fuel	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Total	-	-	-	-	-	-
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	-	-	-			
Total	-	-	-			

TABLE 10-128 Steam-Electric Generation by Type of Cooling—River Basin Group 5.3

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Condenser Cooling Water Requirements
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Required Diversions
(acre-feet per year)

1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-129 Cooling Water Consumption—River Basin Group 5.3

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

TABLE 10-130 Summary of Steam-Electric Power Water Use—River Basin Group 5.3

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	-	-	-	-	-	-
1970	-	-	-	-	-	-
1980	-	-	-	-	-	-
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-131 Power Requirements and Supply—Illinois

	1965	1970	1980	2000	2020
Annual Peak (MW)	-	-	-	-	-
Annual Energy Reqmnts. (10 ⁶ kWh)	-	-	-	-	-
Annual Load Factor (%)	-	-	-	-	-
Installed Capacity (MW)					
Thermal	1,108	1,181	2,928	17,673	59,039
Hydro	-	-	-	-	-
Total	1,108	1,181	2,928	17,673	59,039
Net Generation (10 ⁶ kWh)					
Thermal	4,946	5,212	18,030	116,430	363,022
Hydro	-	-	-	-	-
Total	4,946	5,212	18,030	116,430	363,022

TABLE 10-132 Composition of the Thermal Power Supply—Illinois

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
		<u>1965</u>			<u>1970</u>	
Noncondensing	-	-	-	87	9	113
Fossil Fuel	4,946	51	1,108	5,125	55	1,068
Nuclear	-	-	-	-	-	-
Total	4,946	51	1,108	5,212	50	1,181
		<u>1980</u>			<u>2000</u>	
Noncondensing	-	-	-	-	-	-
Fossil Fuel	3,273	45	828	-	-	-
Nuclear	14,757	80	2,100	116,430	75	17,673
Total	18,030	70	2,928	116,430	75	17,673
		<u>2020</u>				
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	363,022	70	59,039			
Total	363,022	70	59,039			

TABLE 10-133 Steam-Electric Generation by Type of Cooling—Illinois

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	4,946	-	4,946	4,946	-	4,946
1970	5,125	-	5,125	5,125	-	5,125
1980	18,030	-	18,030	3,273	14,757	18,030
2000	116,430	-	116,430	-	116,430	116,430
2020	363,022	-	363,022	-	363,022	363,022

Condenser Cooling Water Requirements
(acre-feet per year)

1965	662,840	-	662,840	662,840	-	662,840
1970	649,440	-	649,440	649,440	-	649,440
1980	2,764,295	-	2,764,295	356,986	2,407,309	2,764,295
2000	15,277,945	-	15,277,945	-	15,277,945	15,277,945
2020	38,723,557	-	38,723,557	-	38,723,557	38,723,557

Required Diversions
(acre-feet per year)

1965	662,840	-	662,840	662,840	-	662,840
1970	649,440	-	649,440	649,440	-	649,440
1980	2,764,295	-	2,764,295	356,986	38,189	395,175
2000	15,277,945	-	15,277,945	-	243,478	243,478
2020	38,723,557	-	38,723,557	-	621,556	621,556

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-134 Cooling Water Consumption—Illinois

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
	(acre-feet per year)					
1965	5,099	-	5,099	5,099	-	5,099
1970	4,956	-	4,956	4,956	-	4,956
1980	21,141	-	21,141	2,724	29,219	31,943
2000	117,303	-	117,303	-	186,288	186,288
2020	298,586	-	298,586	-	475,559	475,559

TABLE 10-135 Summary of Steam-Electric Power Water Use—Illinois

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
	(acre-feet per year)					
1965	662,840	662,840	5,099	662,840	662,840	5,099
1970	649,440	649,440	4,956	649,440	649,440	4,956
1980	2,764,295	2,764,295	21,141	2,764,295	395,175	31,943
2000	15,277,945	15,277,945	117,303	15,277,945	243,478	186,288
2020	38,723,557	38,723,557	298,586	38,723,557	621,556	475,559

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-136 Power Requirements and Supply—Indiana

	1965	1970	1980	2000	2020
Annual Peak (MW)	1,422	2,189	4,640	15,350	38,120
Annual Energy Reqmts. (10 ⁶ kWh)	8,730	13,189	28,762	96,800	241,100
Annual Load Factor (%)	70.1	68.8	70.6	71.8	72.0
Installed Capacity (MW)					
Thermal	2,237	2,937	4,453	7,400	18,357
Hydro	11	11	11	11	11
Total	2,248	2,948	4,464	7,411	18,368
Net Generation (10 ⁶ kWh)					
Thermal	10,317	13,399	21,391	36,356	97,403
Hydro	37	32	39	39	39
Total	10,354	13,431	21,430	36,395	97,442

TABLE 10-137 Composition of the Thermal Power Supply—Indiana

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	-	-	4	159	17	106
Fossil Fuel	10,317	53	2,233	13,240	53	2,831
Nuclear	-	-	-	-	-	-
Total	10,317	53	2,237	13,399	52	2,937
	<u>1980</u>			<u>2000</u>		
Noncondensing	175	20	100	1,248	20	710
Fossil Fuel	16,395	51	3,667	3,155	17	2,143
Nuclear	4,821	80	686	31,953	80	4,547
Total	21,391	55	4,453	36,356	56	7,400
	<u>2020</u>					
Noncondensing	4,568	20	2,600			
Fossil Fuel	-	-	-			
Nuclear	92,835	67	15,757			
Total	97,403	60	18,357			

TABLE 10-138 Steam-Electric Generation by Type of Cooling—Indiana

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	10,317	-	10,317	10,317	-	10,317
1970	13,240	-	13,240	13,240	-	13,240
1980	21,216	-	21,216	6,732	14,484	21,216
2000	35,108	-	35,108	805	34,303	35,108
2020	92,835	-	92,835	-	92,835	92,835

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,350,410	-	1,350,410	1,350,410	-	1,350,410
1970	1,749,835	-	1,749,835	1,749,835	-	1,749,835
1980	2,601,413	-	2,601,413	761,020	1,840,393	2,601,413
2000	4,516,103	-	4,516,103	82,473	4,433,630	4,516,103
2020	9,902,709	-	9,902,709	-	9,902,709	9,902,709

Required Diversions
(acre-feet per year)

1965	1,350,410	-	1,350,410	1,350,410	-	1,350,410
1970	1,749,835	-	1,749,835	1,749,835	-	1,749,835
1980	2,601,413	-	2,601,413	761,020	29,337	790,357
2000	4,516,103	-	4,516,103	82,473	70,672	153,145
2020	9,902,709	-	9,902,709	-	158,949	158,949

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-139 Cooling Water Consumption—Indiana

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	10,342	-	10,342	10,342	-	10,342
1970	13,550	-	13,550	13,550	-	13,550
1980	19,870	-	19,870	5,810	22,446	28,256
2000	34,660	-	34,660	630	54,072	54,702
2020	76,357	-	76,357	-	121,614	121,614

TABLE 10-140 Summary of Steam-Electric Power Water Use—Indiana

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,350,410	1,350,410	10,342	1,350,410	1,350,410	10,342
1970	1,749,835	1,749,835	13,550	1,749,835	1,749,835	13,550
1980	2,601,413	2,601,413	19,870	2,601,413	790,357	28,256
2000	4,516,103	4,516,103	34,660	4,516,103	153,145	54,702
2020	9,902,709	9,902,709	76,357	9,902,709	158,949	121,614

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-141 Power Requirements and Supply—Michigan

	1965	1970	1980	2000	2020
Annual Peak (MW)	7,813	10,660	19,300	55,990	132,450
Annual Energy Reqmts. (10^6 kWh)	43,564	59,833	111,600	335,300	806,500
Annual Load Factor (%)	63.7	64.1	65.8	68.2	69.3
Installed Capacity (MW)					
Thermal	8,001	11,225	24,152	70,068	165,102
Hydro	296	285	2,158	2,158	2,158
Total	8,297	11,510	26,310	72,226	167,260
Net Generation (10^6 kWh)					
Thermal	40,215	54,195	114,247	370,004	894,768
Hydro	1,356	1,249	3,489	3,489	3,489
Total	41,571	55,444	117,736	373,493	898,257

TABLE 10-142 Composition of the Thermal Power Supply—Michigan

	Energy (10^6 kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10^6 kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	416	25	187	1,183	12	1,148
Fossil Fuel	39,618	58	7,739	52,638	61	9,932
Nuclear	181	28	75	374	29	145
Total	40,215	57	8,001	54,195	55	11,225
	<u>1980</u>			<u>2000</u>		
Noncondensing	3,535	20	2,015	10,645	20	6,060
Fossil Fuel	55,106	44	14,224	15,111	18	9,763
Nuclear	55,606	80	7,913	344,248	72	54,245
Total	114,247	54	24,152	370,004	60	70,068
	<u>2020</u>					
Noncondensing	30,752	20	17,505			
Fossil Fuel	-	-	-			
Nuclear	864,016	67	147,597			
Total	894,768	62	165,102			

TABLE 10-143 Steam-Electric Generation by Type of Cooling—Michigan

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	38,620	1,179	39,799	38,620	1,179	39,799
1970	51,561	1,451	53,012	51,561	1,451	53,012
1980	98,544	12,168	110,712	27,542	83,170	110,712
2000	347,112	12,247	359,359	3,959	355,400	359,359
2020	848,733	15,283	864,016	-	864,016	864,016

Condenser Cooling Water Requirements
(acre-feet per year)

1965	5,036,679	171,684	5,208,363	5,036,679	171,684	5,208,363
1970	6,882,843	241,490	7,124,333	6,882,843	241,490	7,124,333
1980	13,202,788	1,851,870	15,054,658	3,032,332	12,022,326	15,054,658
2000	45,136,970	1,583,373	46,720,343	405,599	46,314,744	46,720,343
2020	90,534,349	1,630,238	92,164,587	-	92,164,587	92,164,587

Required Diversions
(acre-feet per year)

1965	5,036,679	2,750	5,039,429	5,036,679	2,750	5,039,429
1970	6,882,843	3,863	6,886,706	6,882,843	3,863	6,886,706
1980	13,202,788	29,414	13,232,202	3,032,332	191,138	3,223,470
2000	45,136,970	25,240	45,162,210	405,599	738,169	1,143,768
2020	90,534,349	26,167	90,560,516	-	1,479,341	1,479,341

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-144 Cooling Water Consumption—Michigan

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	38,414	2,104	40,518	38,414	2,104	40,518
1970	52,526	2,956	55,482	52,526	2,956	55,482
1980	100,897	22,505	123,402	23,144	146,242	169,386
2000	347,503	19,311	366,814	3,096	564,781	567,877
2020	702,016	20,021	722,037	-	1,131,861	1,131,861

TABLE 10-145 Summary of Steam-Electric Power Water Use—Michigan

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	5,208,363	5,039,429	40,518	5,208,363	5,039,429	40,518
1970	7,124,333	6,886,706	55,482	7,124,333	6,886,706	55,482
1980	15,054,658	13,232,202	123,402	15,054,658	3,223,470	169,386
2000	46,720,343	45,162,210	366,814	46,720,343	1,143,768	567,877
2020	92,164,587	90,560,516	722,037	92,164,587	1,479,341	1,131,861

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-146 Power Requirements and Supply—Minnesota

	1965	1970	1980	2000	2020
Annual Peak (MW)	274	466	880	3,200	7,900
Annual Energy Reqmnts. (10 ⁶ kWh)	1,471	2,661	5,100	18,700	46,400
Annual Load Factor (%)	61.3	65.2	66.0	66.5	66.9
Installed Capacity (MW)					
Thermal	293	315	348	3,544	8,802
Hydro	83	83	83	83	83
Total	376	398	431	3,627	8,885
Net Generation (10 ⁶ kWh)					
Thermal	1,106	1,533	1,686	19,388	44,832
Hydro	482	418	401	401	401
Total	1,588	1,951	2,087	19,789	45,233

TABLE 10-147 Composition of the Thermal Power Supply—Minnesota

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	13	21	7	13	19	8
Fossil Fuel	1,093	44	286	1,520	57	307
Nuclear	-	-	-	-	-	-
Total	1,106	43	293	1,533	56	315
	<u>1980</u>			<u>2000</u>		
Noncondensing	14	20	8	300	20	171
Fossil Fuel	1,672	56	340	2,089	25	954
Nuclear	-	-	-	16,999	80	2,419
Total	1,686	55	348	19,388	62	3,544
	<u>2020</u>					
Noncondensing	1,806	20	1,028			
Fossil Fuel	-	-	-			
Nuclear	43,026	63	7,774			
Total	44,832	58	8,802			

TABLE 10-148 Steam-Electric Generation by Type of Cooling—Minnesota

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	1,093	-	1,093	1,093	-	1,093
1970	1,520	-	1,520	1,520	-	1,520
1980	1,672	-	1,672	1,444	228	1,672
2000	19,088	-	19,088	-	19,088	19,088
2020	43,026	-	43,026	-	43,026	43,026

Condenser Cooling Water Requirements
(acre-feet per year)

1965	203,798	-	203,798	203,798	-	203,798
1970	279,841	-	279,841	279,841	-	279,841
1980	182,364	-	182,364	157,496	24,868	182,364
2000	2,424,136	-	2,424,136	-	2,424,136	2,424,136
2020	4,589,540	-	4,589,540	-	4,589,540	4,589,540

Required Diversions
(acre-feet per year)

1965	203,798	-	203,798	203,798	-	203,798
1970	279,841	-	279,841	279,841	-	279,841
1980	182,364	-	182,364	157,496	397	157,893
2000	2,424,136	-	2,424,136	-	38,642	38,642
2020	4,589,540	-	4,589,540	-	73,667	73,667

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-149 Cooling Water Consumption—Minnesota

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	1,553	-	1,553	1,553	-	1,553
1970	2,135	-	2,135	2,135	-	2,135
1980	1,392	-	1,392	1,202	304	1,506
2000	18,598	-	18,598	-	29,566	29,566
2020	35,389	-	35,389	-	56,363	56,363

TABLE 10-150 Summary of Steam-Electric Power Water Use—Minnesota

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	203,798	203,798	1,553	203,798	203,798	1,553
1970	279,841	279,841	2,135	279,841	279,841	2,135
1980	182,364	182,364	1,392	182,364	157,893	1,506
2000	2,424,136	2,424,136	18,598	2,424,136	38,642	29,566
2020	4,589,540	4,589,540	35,389	4,589,540	73,667	56,363

¹ 1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

² 1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-151 Power Requirements and Supply—New York

	1965	1970	1980	2000	2020
Annual Peak (MW)	4,463	5,391	8,552	22,701	53,933
Annual Energy Reqmnts. (10 ⁶ kWh)	26,703	31,077	50,932	134,232	317,016
Annual Load Factor (%)	68.3	65.8	67.8	67.3	66.9
Installed Capacity (MW)					
Thermal	2,737	3,936	10,035	23,302	63,959
Hydro	3,539	3,544	3,544	4,504	7,804
Total	6,276	7,480	13,579	27,806	71,763
Net Generation (10 ⁶ kWh)					
Thermal	14,503	17,952	58,725	130,768	336,559
Hydro	18,481	23,901	20,554	22,152	27,645
Total	32,984	41,853	79,279	152,920	364,204

TABLE 10-152 Composition of the Thermal Power Supply—New York

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
		<u>1965</u>			<u>1970</u>	
Noncondensing	-	-	3	8	2	45
Fossil Fuel	14,503	61	2,734	14,085	59	2,732
Nuclear	-	-	-	3,859	38	1,159
Total	14,503	60	2,737	17,952	52	3,936
		<u>1980</u>			<u>2000</u>	
Noncondensing	76	20	43	2,837	20	1,602
Fossil Fuel	20,464	56	4,155	32,614	61	6,100
Nuclear	38,185	74	5,837	95,317	70	15,600
Total	58,725	67	10,035	130,768	64	23,302
		<u>2020</u>				
Noncondensing	6,996	20	3,959			
Fossil Fuel	36,090	43	9,500			
Nuclear	293,473	66	50,500			
Total	336,559	60	63,959			

TABLE 10-153 Steam-Electric Generation by Type of Cooling—New York

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	14,503	-	14,503	14,503	-	14,503
1970	17,944	-	17,944	17,944	-	17,944
1980	58,649	-	58,649	50,921	7,728	58,649
2000	127,931	-	127,931	33,420	94,511	127,931
2020	329,563	-	329,563	-	329,563	329,563

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,891,276	-	1,891,276	1,891,276	-	1,891,276
1970	3,482,773	-	3,482,773	3,482,773	-	3,482,773
1980	8,389,650	-	8,389,650	7,128,981	1,260,669	8,389,650
2000	15,848,801	-	15,848,801	4,197,044	11,651,757	15,848,801
2020	34,843,028	-	34,843,028	-	34,843,028	34,843,028

Required Diversions
(acre-feet per year)

1965	1,891,276	-	1,891,276	1,891,276	-	1,891,276
1970	3,482,773	-	3,482,773	3,482,773	-	3,482,773
1980	8,389,650	-	8,389,650	7,128,981	12,626	7,141,607
2000	15,848,801	-	15,848,801	4,197,044	153,644	4,350,688
2020	34,843,028	-	34,843,028	-	487,544	487,544

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-154 Cooling Water Consumption—New York

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	13,843	-	13,843	13,843	-	13,843
1970	42,489	-	42,489	42,489	-	42,489
1980	63,634	-	63,634	53,974	9,660	63,634
2000	121,707	-	121,707	32,249	117,555	149,804
2020	267,716	-	267,716	-	373,026	373,026

TABLE 10-155 Summary of Steam-Electric Power Water Use—New York

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,891,276	1,891,276	13,843	1,891,276	1,891,276	13,843
1970	3,482,773	3,482,773	42,489	3,482,773	3,482,773	42,489
1980	8,389,650	8,389,650	63,634	8,389,650	7,141,607	63,634
2000	15,848,801	15,848,801	121,707	15,848,801	4,350,688	149,804
2020	34,843,028	34,843,028	267,716	34,843,028	487,544	373,026

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-156 Power Requirements and Supply—Ohio

	1965	1970	1980	2000	2020
Annual Peak (MW)	4,268	5,916	10,568	34,600	86,536
Annual Energy Reqmts. (10 ⁶ kWh)	25,074	36,134	62,938	206,044	515,456
Annual Load Factor (%)	67.1	69.7	67.8	67.8	67.8
Installed Capacity (MW)					
Thermal	3,450	4,576	6,132	31,636	84,050
Hydro	-	-	-	-	-
Total	<u>3,450</u>	<u>4,576</u>	<u>6,132</u>	<u>31,636</u>	<u>84,050</u>
Net Generation (10 ⁶ kWh)					
Thermal	15,536	19,038	37,237	172,387	443,761
Hydro	-	-	-	-	-
Total	<u>15,536</u>	<u>19,038</u>	<u>37,237</u>	<u>172,387</u>	<u>443,761</u>

TABLE 10-157 Composition of the Thermal Power Supply—Ohio

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	93	20	52	133	8	188
Fossil Fuel	15,443	52	3,398	18,905	49	4,388
Nuclear	-	-	-	-	-	-
Total	<u>15,536</u>	<u>51</u>	<u>3,450</u>	<u>19,038</u>	<u>47</u>	<u>4,576</u>
	<u>1980</u>			<u>2000</u>		
Noncondensing	496	30	188	8,566	20	4,876
Fossil Fuel	30,376	69	5,038	5,611	17	3,810
Nuclear	6,365	80	906	158,210	78	22,950
Total	<u>37,237</u>	<u>69</u>	<u>6,132</u>	<u>172,387</u>	<u>62</u>	<u>31,636</u>
	<u>2020</u>					
Noncondensing	22,231	20	12,654			
Fossil Fuel	-	-	-			
Nuclear	421,530	67	71,396			
Total	<u>443,761</u>	<u>60</u>	<u>84,050</u>			

TABLE 10-158 Steam-Electric Generation by Type of Cooling—Ohio

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	15,443	-	15,443	15,443	-	15,443
1970	18,905	-	18,905	18,905	-	18,905
1980	30,376	6,365	36,741	30,376	6,365	36,741
2000	157,704	6,117	163,821	5,611	158,210	163,821
2020	421,530	-	421,530	-	421,530	421,530

Condenser Cooling Water Requirements
(acre-feet per year)

1965	2,104,721	-	2,104,721	2,104,721	-	2,104,721
1970	3,808,374	-	3,808,374	3,808,374	-	3,808,374
1980	3,313,110	1,038,322	4,351,432	3,313,110	1,038,322	4,351,432
2000	20,532,490	802,672	21,335,162	574,847	20,760,315	21,335,162
2020	44,964,605	-	44,964,605	-	44,964,605	44,964,605

Required Diversions
(acre-feet per year)

1965	2,104,721	-	2,104,721	2,104,721	-	2,104,721
1970	3,808,374	-	3,808,374	3,808,374	-	3,808,374
1980	3,313,110	16,472	3,329,582	3,313,110	16,472	3,329,582
2000	20,532,490	12,792	20,545,282	574,847	330,853	905,700
2020	44,964,605	-	44,964,605	-	721,731	721,731

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-159 Cooling Water Consumption—Ohio

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	16,058	-	16,058	16,058	-	16,058
1970	45,981	-	45,981	45,981	-	45,981
1980	24,912	12,603	37,515	24,912	12,603	37,515
2000	157,990	9,787	167,777	4,373	253,139	257,512
2020	345,657	-	345,657	-	552,204	552,204

TABLE 10-160 Summary of Steam-Electric Power Water Use—Ohio

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Water Diversion	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Water Diversion	Cooling Water Consumption
(acre-feet per year)						
1965	2,104,721	2,104,721	16,058	2,104,721	2,104,721	16,058
1970	3,808,374	3,808,374	45,981	3,808,374	3,808,374	45,981
1980	4,351,432	3,329,582	37,515	4,351,432	3,329,582	37,515
2000	21,335,162	20,545,282	167,777	21,335,162	905,700	257,512
2020	44,964,605	44,964,605	345,657	44,964,605	721,731	552,204

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-161 Power Requirements and Supply—Pennsylvania

	1965	1970	1980	2000	2020
Annual Peak (MW)	262	367	768	2,318	5,620
Annual Energy Reqmnts. (10 ⁶ kWh)	1,453	2,086	4,375	13,200	32,000
Annual Load Factor (%)	63.3	64.9	64.9	64.8	64.8
Installed Capacity (MW)					
Thermal	123	123	124	-	-
Hydro	-	-	-	-	-
Total	123	123	124	-	-
Net Generation (10 ⁶ kWh)					
Thermal	468	587	426	-	-
Hydro	-	-	-	-	-
Total	468	587	426	-	-

TABLE 10-162 Composition of the Thermal Power Supply—Pennsylvania

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	10	29	4	12	34	4
Fossil Fuel	458	44	119	575	55	119
Nuclear	-	-	-	-	-	-
Total	468	43	123	587	54	123
	<u>1980</u>			<u>2000</u>		
Noncondensing	9	20	5	-	-	-
Fossil Fuel	417	40	119	-	-	-
Nuclear	-	-	-	-	-	-
Total	426	39	124	-	-	-
	<u>2020</u>					
Noncondensing	-	-	-			
Fossil Fuel	-	-	-			
Nuclear	-	-	-			
Total	-	-	-			

TABLE 10-163 Steam-Electric Generation by Type of Cooling—Pennsylvania

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	458	-	458	458	-	458
1970	575	-	575	575	-	575
1980	417	-	417	417	-	417
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Condenser Cooling Water Requirements
(acre-feet per year)

1965	128,459	-	128,459	128,459	-	128,459
1970	161,555	-	161,555	161,555	-	161,555
1980	116,959	-	116,959	116,959	-	116,959
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

Required Diversions
(acre-feet per year)

1965	128,459	-	128,459	128,459	-	128,459
1970	161,555	-	161,555	161,555	-	161,555
1980	116,959	-	116,959	116,959	-	116,959
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-164 Cooling Water Consumption—Pennsylvania

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
	(acre-feet per year)					
1965	1,567	-	1,567	1,567	-	1,567
1970	1,971	-	1,971	1,971	-	1,971
1980	1,429	-	1,429	1,429	-	1,429
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

TABLE 10-165 Summary of Steam-Electric Power Water Use—Pennsylvania

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
	(acre-feet per year)					
1965	128,459	128,459	1,567	128,459	128,459	1,567
1970	161,555	161,555	1,971	161,555	161,555	1,971
1980	116,959	116,959	1,429	116,959	116,959	1,429
2000	-	-	-	-	-	-
2020	-	-	-	-	-	-

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-166 Power Requirements and Supply—Wisconsin

	1965	1970	1980	2000	2020
Annual Peak (MW)	2,139	2,955	5,430	16,610	40,080
Annual Energy Reqmnts. (10 ⁶ kWh)	11,611	16,323	31,100	96,800	234,400
Annual Load Factor (%)	62.0	63.1	65.2	66.3	66.6
Installed Capacity (MW)					
Thermal	2,918	4,452	7,275	20,704	49,767
Hydro	146	144	144	144	144
Total	3,064	4,596	7,419	20,848	49,911
Net Generation (10 ⁶ kWh)					
Thermal	11,447	17,788	35,713	104,128	254,130
Hydro	704	674	680	680	680
Total	12,151	18,462	36,393	104,808	254,810

TABLE 10-167 Composition of the Thermal Power Supply—Wisconsin

	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)	Energy (10 ⁶ kWh)	Capacity Factor (%)	Capacity (MW)
	<u>1965</u>			<u>1970</u>		
Noncondensing	29	28	12	141	12	132
Fossil Fuel	11,418	45	2,906	17,614	53	3,796
Nuclear	-	-	-	33	1	524
Total	11,447	45	2,918	17,788	46	4,452
	<u>1980</u>			<u>2000</u>		
Noncondensing	1,456	20	831	2,687	20	1,529
Fossil Fuel	17,862	49	4,111	15,183	25	6,900
Nuclear	16,395	80	2,333	86,258	80	12,275
Total	35,713	56	7,275	104,128	57	20,704
	<u>2020</u>					
Noncondensing	8,980	20	5,112			
Fossil Fuel	-	-	-			
Nuclear	245,150	62	44,655			
Total	254,130	58	49,767			

TABLE 10-168 Steam-Electric Generation by Type of Cooling—Wisconsin

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(Million kWh)						
1965	11,418	-	11,418	11,418	-	11,418
1970	17,647	-	17,647	17,647	-	17,647
1980	34,257	-	34,257	20,612	13,645	34,257
2000	101,441	-	101,441	2,012	99,429	101,441
2020	245,150	-	245,150	-	245,150	245,150

Condenser Cooling Water Requirements
(acre-feet per year)

1965	1,486,216	-	1,486,216	1,486,216	-	1,486,216
1970	2,289,046	-	2,289,046	2,289,046	-	2,289,046
1980	4,622,725	-	4,622,725	2,439,254	2,183,471	4,622,725
2000	12,894,763	-	12,894,763	206,130	12,688,633	12,894,763
2020	26,150,194	-	26,150,194	-	26,150,194	26,150,194

Required Diversions
(acre-feet per year)

1965	1,486,216	-	1,486,216	1,486,216	-	1,486,216
1970	2,289,046	-	2,289,046	2,289,046	-	2,289,046
1980	4,622,725	-	4,622,725	2,439,254	34,585	2,473,839
2000	12,894,763	-	12,894,763	206,130	202,293	408,423
2020	26,150,194	-	26,150,194	-	419,739	419,739

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-169 Cooling Water Consumption—Wisconsin

Year	CASE I ¹			CASE II ²		
	Flow Through	Supplemental Cooling	Total	Flow Through	Supplemental Cooling	Total
(acre-feet per year)						
1965	12,687	-	12,687	12,687	-	12,687
1970	17,469	-	17,469	17,469	-	17,469
1980	35,329	-	35,329	18,627	26,511	45,138
2000	98,937	-	98,937	1,574	154,776	156,350
2020	201,554	-	201,554	-	321,147	321,147

TABLE 10-170 Summary of Steam-Electric Power Water Use—Wisconsin

Year	CASE I ¹			CASE II ²		
	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption	Condenser Cooling Water Requirements	Required Diversions	Cooling Water Consumption
(acre-feet per year)						
1965	1,486,216	1,486,216	12,687	1,486,216	1,486,216	12,687
1970	2,289,046	2,289,046	17,469	2,289,046	2,289,046	17,469
1980	4,622,725	4,622,725	35,329	4,622,725	2,473,839	45,138
2000	12,894,763	12,894,763	98,937	12,894,763	408,423	156,350
2020	26,150,194	26,150,194	201,554	26,150,194	419,739	321,147

¹1970 through 2020 assumes all flow through cooling except for known supplemental cooling systems as of December 31, 1970.

²1970 through 2020 assumes all supplemental cooling except for known flow through systems as of December 31, 1970.

TABLE 10-171 Undeveloped Conventional Hydroelectric Power Sites

River Basin Group and Site	River	State	Installed Capacity (kW)	Average Annual Generation (1000 kWh)	Usable Power Storage Capacity (1000 ac-ft)	Gross Static Head (ft)
1.0 Lake Superior						
<u>Sturgeon River Basin</u>						
Lower Plant	Sturgeon	Mich.	16,300	19,100	NA	90
Big Falls	Sturgeon	Mich.	17,600	23,800	46	110
Tibbet Falls	Sturgeon	Mich.	12,000	12,200	46	112
			45,900	55,100		
<u>Ontonagon River Basin</u>						
Grand Rapids	Ontonagon	Mich.	4,800	32,000	NA	55
Forks	Ontonagon	Mich.	4,200	28,000	NA	40
Hooper	W.Br.Ontonagon	Mich.	6,000	23,000	NA	70
			15,000	83,000		
<u>St. Louis River Basin</u>						
Grand Rapids	St. Louis	Minn.	10,000	57,000	300	66
			10,000	57,000		
<u>Minor River Basins</u>						
Baptism	Baptism	Minn.	11,400	60,000	33	598
Lower Poplar	Poplar	Minn.	4,500	26,000	U	278
Upper Poplar	Poplar	Minn.	7,400	38,000	93	460
Cascade	Cascade	Minn.	5,600	26,800	35	663
Brule No. 5	Brule	Minn.	6,200	33,800	U	270
Brule No. 4	Brule	Minn.	7,200	39,300	U	320
Brule No. 3	Brule	Minn.	5,100	28,400	U	230
High Falls	Pigeon	Minn.	10,600	45,300	U	225
Tahquamenon Falls	Tahquamenon	Mich.	4,500	30,000	NA	93
Orienta Falls	Iron	Wis.	4,900	27,000	44	104
			67,400	354,600		
Total - Lake Superior			138,300	549,700		
2.0 Lake Michigan						
<u>Manistee River Basin</u>						
Anderson	Manistee	Mich.	10,000	25,000	NA	19
High Bridge	Manistee	Mich.	6,800	16,300	NA	15
Wilson	S. Br. Manistee	Mich.	8,200	20,000	NA	110
Lower Sibley	Manistee	Mich.	17,000	41,000	U	55
Sherman	Manistee	Mich.	16,000	38,000	U	61
Manton	Manistee	Mich.	9,500	22,700	U	45
Walton	Manistee	Mich.	5,600	13,300	U	31
Sands	Manistee	Mich.	10,000	23,500	NA	66
Dutch John	Manistee	Mich.	5,000	12,000	NA	40
			88,100	211,800		

TABLE 10-171(continued) Undeveloped Conventional Hydroelectric Power Sites

River Basin Group and Site	River	State	Installed Capacity (kW)	Average Annual Generation (1000 kWh)	Usable Power Storage Capacity (1000 ac-ft)	Gross Static Head (ft)
2.0 Lake Michigan (contd)						
<u>Grand River Basin</u>						
Grand Rapids	Grand	Mich.	6,700 6,700	30,000 30,000	U	17
<u>Kalamazoo River Basin</u>						
None			0 0	0 0		
<u>St. Joseph River Basin</u>						
Kings Landing	St. Joseph	Mich.	7,200 7,200	29,400 29,400	U	18
<u>Fox River Basin</u>						
Leeman	Wolf	Wis.	5,000 5,000	12,400 12,400	U	20
<u>Menominee River Basin</u>						
Chappie Rapids	Menominee	Mich.	5,200	24,000	U	16
Pemene Falls	Menominee	Mich.	10,000	40,000	U	32
Pemene Dam	Menominee	Mich.	7,000	33,000	U	28
Sturgeon Falls	Menominee	Mich.	1,500	800	NA	26
Sand Portage	Menominee	Mich.	4,600	23,000	U	43
Sand Portage	Menominee	Wis.	4,600	23,000	U	43
Big Quinnesec	Menominee	Mich.	8,000 40,900	32,000 175,800	U	92
<u>Minor River Basins</u>						
Bridgeton	Muskegon	Mich.	6,000	25,700	U	22
Bacon	Muskegon	Mich.	15,000	36,000	NA	31
Stiles	Oconto	Wis.	500	2,000	U	20
Roaring Rapids	Peshtigo	Wis.	9,700 31,200	49,400 113,100	U	200
Total - Lake Michigan			179,100	572,500		
3.0 Lake Huron						
<u>Saginaw River Basin</u>						
None			0 0	0 0		

TABLE 10-171(continued) Undeveloped Conventional Hydroelectric Power Sites

River Basin Group and Site	River	State	Installed Capacity (kW)	Average Annual Generation (1000 kWh)	Usable Power Storage Capacity (1000 ac-ft)	Gross Static Head (ft)
3.0 Lake Huron (contd)						
<u>Au Sable River Basin</u>						
Thompson	Au Sable	Mich.	12,000	36,500	NA	48
Upper Flat Rock	Au Sable	Mich.	25,000	68,000	NA	107
Baker Bridge	Au Sable	Mich.	5,500	13,300	NA	32
Eaton	Au Sable	Mich.	5,000	10,700	NA	48
			47,500	128,500		
<u>St. Marys River Basin</u>						
None			0	0		
			0	0		
<u>Minor River Basins</u>						
None			0	0		
			0	0		
Total - Lake Huron			47,500	128,500		
4.0 Lake Erie						
<u>Cattaraugus Creek Basin</u>						
Chautauqua Creek	Chautauqua Creek	N. Y.	37,000	108,000	78	797
			37,000	108,000		
<u>Huron River Basin</u>						
None			0	0		
			0	0		
<u>Minor River Basins</u>						
Defiance	Augalize	Ohio	5,000	8,600	12	24
			5,000	8,600		
Total - Lake Erie			42,000	116,600		
5.0 Lake Ontario						
<u>Black River Basin</u>						
Woods Falls	Black	N. Y.	10,000	40,000	U	45
Felts Mills	Black	N. Y.	10,000	85,000	U	44
High Falls	Beaver	N. Y.	1,600	*	NA	95
Lyon Falls	Black	N. Y.	11,100	64,000	U	67
Moose River	Moose	N. Y.	18,800	66,000	U	140
Fowlersville	Moose	N. Y.	30,100	114,000	U	195
Shuetown	Moose	N. Y.	34,000	130,000	U	220
Mill No. 3**	Black	N. Y.	-2,255	-2,000	U	65
Mill No. 5**	Moose	N. Y.	-2,500	-3,000	U	32
			110,845	494,000		

TABLE 10-171(continued) Undeveloped Conventional Hydroelectric Power Sites

River Basin Group and Site	River	State	Installed Capacity (kW)	Average Annual Generation (1000 kWh)	Usable Power Storage Capacity (1000 ac-ft)	Gross Static Head (ft)
5.0 Lake Ontario (contd)						
<u>Salmon River Basin</u>						
Lighthouse Hill	Salmon	N. Y.	3,750 3,750	10,000 10,000	U	65
<u>Oswego River Basin</u>						
Fulton No. 2	E.Br. Fish Creek	N. Y.	10,500	37,700	U	160
High Dam No. 6	Oswego	N. Y.	1,400 11,900	4,000 41,700	U	20
<u>Genesee River Basin</u>						
Rochester Upper Falls	Genesee	N. Y.	16,700	137,500	U	120
Canaseraga	Canaseraga Creek	N. Y.	8,000	28,000	10	390
Mt. Morris	Genesee	N. Y.	40,000	95,000	72	122
Portage	Genesee	N. Y.	82,000	230,000	142	410
Station No. 2**	Genesee	N. Y.	-6,500	-51,000	U	91
Station No. 26**	Genesee	N. Y.	-3,000	-16,000	NA	25
Station No. 160**	Genesee	N. Y.	- 340 136,860	- 2,900 420,600	NA	20
<u>Oak Orchard Creek Basin</u>						
None			0 0	0 0		
<u>Niagara River Basin</u>						
None			0 0	0 0		
<u>Barge Canal Basin</u>						
None			0 0	0 0		
<u>St. Regis River Basin</u>						
Lower Parishville	W.Br.St.Regis	N. Y.	11,000	30,000	U	144
Sylan Falls	W.Br.St.Regis	N. Y.	16,300	41,000	26	220
Fort Jackson	E.Br.St.Regis	N. Y.	25,500	71,000	U	240
Nicholville	E.Br.St.Regis	N. Y.	26,900	71,000	U	260
Parishville**	E.Br.St.Regis	N. Y.	-2,400 77,300	-15,000 198,000	U	144
<u>Raquette River Basin</u>						
Sugar Island	Raquette	N. Y.	20,800	29,000	U	63
Hannawa	Raquette	N. Y.	25,200	30,000	U	82
Colton	Raquette	N. Y.	87,400	108,000	U	285
Higley	Raquette	N. Y.	12,100	13,000	U	44
Moosehead Rapids	Raquette	N. Y.	29,000	66,000	U	85
Piercefield	Raquette	N. Y.	9,000 183,500	12,000 258,000	U	35

TABLE 10-171(continued) Undeveloped Conventional Hydroelectric Power Sites

River Basin Group and Site	River	State	Installed Capacity (kW)	Average Annual Generation (1000 kWh)	Usable Power Storage Capacity (1000 ac-ft)	Gross Static Head (ft)
5.0 Lake Ontario (contd)						
<u>Grass River Basin</u>						
Pyrites	Grass	N. Y.	15,000	45,000	U	130
Jackson Falls	Grass	N. Y.	7,900	24,000	U	70
Clarksboro	S.Br.Grass	N. Y.	11,600	24,000	U	200
Rainbow Falls	S.Br.Grass	N. Y.	11,700	25,000	U	200
Copper Rocks Falls	S.Br.Grass	N. Y.	7,000	13,000	U	120
Pyrites**	Grass	N. Y.	-1,400	-9,000	U	75
			51,800	122,000		
<u>Oswegatchie River Basin</u>						
Wegatchie	Oswegatchie	N. Y.	8,000	40,000	U	50
Hailesboro	Oswegatchie	N. Y.	23,000	108,000	U	150
Emeryville	Oswegatchie	N. Y.	9,000	42,000	U	60
Cotton Rapids	E.Br.Oswegatchie	N. Y.	12,700	58,000	U	190
Madison Chute	E.Br.Oswegatchie	N. Y.	6,400	29,000	U	102
Natural Dam**	Oswegatchie	N. Y.	-1,200	-3,500	U	20
Plant No. 4**	Oswegatchie	N. Y.	-1,320	-7,200	NA	30
Plant No. 7**	Oswegatchie	N. Y.	- 900	-5,000	NA	15
Emeryville**	Oswegatchie	N. Y.	-1,320	-8,000	U	32
Oswegatchie**	E.Br.Oswegatchie	N. Y.	- 560	-6,000	U	10
So.Edwards No. 2**	E.Br.Oswegatchie	N. Y.	-2,680	-20,000	U	82
			51,120	227,300		
Total - Lake Ontario			627,075	1,771,600		
Total - Great Lakes Basin			1,033,975	3,138,900		

NA - Data not available.

U - Usable power storage capacity is less than 5,000 acre-feet.

* - Additional capacity at existing developed site with no additional energy generation.

** - Existing plants (26,375 kW and 148,600 thousand kWh) subject to possible redevelopment which could be replaced by a potential plant listed. The capacity and generation are shown as negative figures so that only the net gain due to the redevelopment is in the total river basin group.

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